

Benefits and Costs of Oil Self-sufficiency in Canada

J. A. Dawson and Z. C. Slagorsky



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CANADIAN ENERGY RESEARCH INSTITUTE
3512 - 33 STREET N.W.
CALGARY, ALBERTA
T2L 2A6
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Preface

This study draws heavily on work done by various staff members at the Canadian Energy Research Institute over the past year. The work was completed prior to the announcement of the National Energy Program on October 28, 1980, but is nevertheless relevant to many of the issues raised. Several of the chapters were previously issued as working papers authored by W. B. Friedenberq, A. J. Nixon (also under the name A. J. Walsh), and Z. C. Slagorsky. The responsibility for the content of the individual chapters is as indicated in each of them. Chapters 3 and 4, which are summaries of material contained in the working papers, were prepared by E. A. Howling, who also contributed to the overall editing of the study. The preparation of the report for publication was carried out by Barbara Lees.

Chapter 1

INTRODUCTION AND SUMMARY

Introduction

Few issues have drawn the attention that energy has over the past decade. In Canada, concern about prospective oil and gas availability and requirements, pricing and transportation have rivalled the attention given to the political future of the country and the nature of the confederation under which it will be governed. Energy self-sufficiency or self-reliance have been proposed as goals for policy. Concurrently, there have also been proposals for an industrial policy for Canada, for transportation policy, etc. These specific proposals all have major economic implications as did the national policy of 1879 and the decision to complete the transcontinental railway in the last century, the construction of the St. Lawrence Seaway and major oil and gas pipelines in the 1950s, and the introduction and extension of social programs in the 1960s and early 1970s.

The issue of energy self-sufficiency for Canada comes down to how much of our prospective oil requirements are to be met from Canadian sources. For natural gas and electricity we meet all of our requirements and have export surpluses. Projections indicate that this situation will continue for the foreseeable future. For oil, however, the situation is different. While we reached the point where we were exporting an amount of oil equivalent to our imports in the early 1970s, crude oil producibility in Canada has since been declining. For conventional sources in the western sedimentary basin, production is about 20 percent below the peak that was reached and the decline will continue in the years ahead.

With respect to the amount of oil we use, even if we move vigorously on measures to conserve energy and on the substitution of various other forms of energy for oil, it is unlikely that we can achieve more than a holding of the line on the annual consumption of oil in Canada over the coming decade (see Chapter 3). In the light of these prospects it is evident that Canada must either increase oil imports or increase expenditures in Canada on non-conventional, frontier and offshore sources of oil.

In 1979, Canada imported about 610 thousand barrels of oil per day (97 thousand cubic metres). Of this, about 490 thousand barrels (78 thousand cubic metres) were direct imports and about 120 thousand barrels (19 thousand cubic metres) were in the form of exchanges with the United States for oil that we exported to that country. With Canadian requirements for crude oil and equivalent at 1.97 million barrels per day in 1979 (313 thousand cubic metres), direct imports accounted for 25 percent of this total. Canada's net imports of oil are lower than this because we continue to export heavy oil to the United States. Exports other than exchanges totalled 157 thousand barrels per day in 1979 (25 thousand cubic metres).

Looking ahead, it is evident that sufficient oil could be produced in Canada to meet projected Canadian demand if there is sufficient lead time to develop new capacity to offset declining conventional production from sources in the western sedimentary basin and to provide Canadian production in place of the presently imported oil. How soon this could be achieved is a matter, not only of the prices and returns to producers, but also of the speed at which major projects can proceed through the regulatory, planning and financing processes. It is likely that our dependence on imports will increase in the next few years, with the level in 1985 considerably higher than it was in 1979. Decisions made during the next few years will determine whether or not we begin to move towards self-sufficiency in the latter part of the decade.

In this study, continued growth in the Canadian and world economies is assumed. It is against this growth that Canadian self-sufficiency in oil is examined. We have not examined scenarios in which there is disruption in economic growth nor situations in which the rate of growth is otherwise substantially reduced.

In the very long run there will obviously have to be a transition to other forms of energy from oil and gas. They are both derived from non-renewable sources. As we move towards the twenty-first century, the alternatives to these energy sources will become clearer. In any event, costs and availability will depend more on world than on Canadian developments. As Canada makes commitments to use its remaining oil reserves, it will have to concurrently lay the groundwork for participation in a world where alternative fuels become more significant.

Summary

In this study we review briefly the benefits that Canada might obtain from oil self-sufficiency. The means of achieving this objective are then considered, and information on costs is examined. Thus, in a sense, this is a study of the benefits and costs of oil self-sufficiency in Canada. The material that is drawn together, however, does not constitute a benefit-cost analysis in the formal sense of measuring the streams of benefits and costs and relating them through the use of a discount rate.

Our review of the potential benefits consists of a consideration of the arguments presented in the case for self-sufficiency. The strongest reason for Canada to seek to produce sufficient oil to meet its requirements is that the risks associated with continued dependence on insecure foreign sources of supply are high. Furthermore, the costs of imported oil are likely to continue to be higher than the costs of oil that could be developed from Canadian sources. Also, some suppliers are likely to be reluctant to give very high priority to shipping oil to Canada as the world's remaining reserves of oil are depleted.

The issue of oil self-sufficiency is more a matter of the rate at which Canada can and should move to meet its own requirements. In Part II we examine the various elements in achieving self-sufficiency. Figure 1.1 brings together the results of our examination of prospective oil consumption and the possible future production of oil in Canada

In 1979, our rate of imports was about 500 thousand barrels of oil (78 thousand cubic metres) per day, or about 25 percent of Canada's requirements. If oil consumption continues to increase at the same rate as it did in the 1970s (2.5 percent annually), by 1985 we'll be using 2.2 million barrels per day. Potential production of light and medium oil would appear to be of the order of 1.3 million barrels per day and if we add to this 100 thousand barrels of heavy oil used in Canada, imports of 800 thousand barrels per day would be required.

By 1990, with consumption at 2.5 million barrels per day and production of light and medium oil and upgraded heavy oil at 2.0 million barrels daily and 100 thousand barrels daily of heavy oil used in Canada, imports would be at a rate of 400 thousand barrels per day. By 1995, consumption would have risen to 2.8 million barrels per day and, if production reaches 2.2 million barrels per day, imports would have risen to 600 thousand barrels per day.

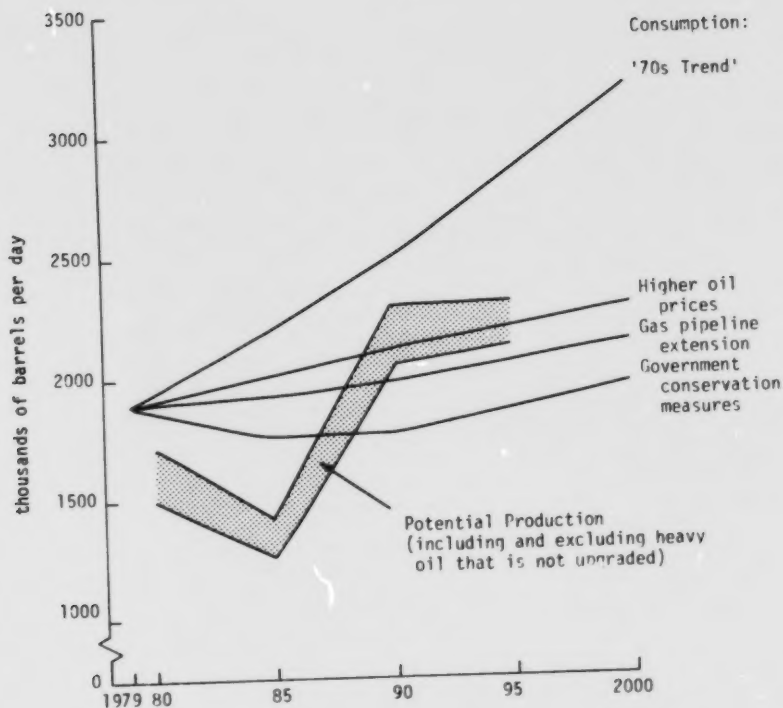


FIGURE 1.1: Prospects for Consumption and Future Production of Oil in Canada

NOTE: 1 cubic metre = 6.293 barrels

To achieve the increased Canadian oil production represented in this scenario would entail a shift from the present 90 percent of Canadian oil being derived from primary and secondary recovery in the western sedimentary basin (77 percent light and medium oil and 13 percent heavy oil) to 30 percent in 1995 (26 percent light and medium and 4 percent heavy oil, not up-graded). The remainder of the oil would be derived from oil sands (35 percent), heavy oil that is upgraded (4 percent), enhanced oil recovery (9 percent), and frontier oil (22 percent). The details of these estimates are provided in Chapter 4 as are the estimated supply prices of oil from the various sources.

It is obvious that, with oil consumption increasing at 2.5 percent per annum, self-sufficiency is not achievable even with substantial expansion of new sources of production. On the consumption side, however, there are some steps that could be taken that would reduce the rate of growth in the amount of oil used in Canada. Increases in the rate of price increase from an annual rate of about \$5 per barrel between now and 1985 and \$8 per barrel to 1990 could lessen the rate of growth of oil consumption in Canada to an estimated 1.0 percent per annum between now and the year 2000. This reduction in the rate of increase in oil consumption, coupled with extension of the natural gas pipeline system to enable additional substitution of gas for oil in Quebec, the Maritime provinces and Vancouver Island, could further reduce the rate of increase in oil consumption to 0.6 percent per annum. With these two features, imports could be held to 500 thousand barrels per day by 1985 and eliminated by 1990.

Consideration has also been given to the potential additional effects of government legislated conservation measures in the residential, commercial and transportation sectors of the economy. They could reduce further the consumption of oil. Even with the full set of measures, however, including higher rates of price increase, extension of the natural gas pipeline system, and the conservation measures, Canada would continue to have to import oil in the mid-1980s at a rate of at least 300 thousand barrels per day.

The potential future production of oil included in the above review is based on an examination of various projections of the amounts of oil that could be supplied from Canadian sources. Consideration of the costs of oil from these sources indicates, however, that much of the oil could only be produced at costs above the present wellhead price of \$17.75 per barrel.

A review of a number of the industry submissions to the National Energy Board for the energy supply and demand hearings in the fall of 1980 also indicates that substantial oil imports will be required in the mid-1980s. Their view is that oil self-sufficiency cannot be attained until the early to mid-1990s even with decisions on pricing and revenue sharing that are favourable to investment.

There are also some possibilities in the development of alternative liquid fuels. A number of these are considered in Chapter 5, including methanol, ethanol and liquefied coal. Like most of the oil supplies, they would require increased oil prices to stimulate their development and, in addition, the solution of a number of production and marketing problems.

In Part III of this study consideration is given to the relation of oil pricing to costs and to potential problems associated with the inadequacy of cost information. The current set of fiscal incentives in the oil and gas industry is also reviewed.

It is clear from the examination carried out in the earlier chapters that, for oil self-sufficiency to be achieved, the Canadian price of crude oil must rise. To ascertain how much it would have to rise entails determining supply prices of oil (see Chapter 4). This is a formidable problem. It is critical, however, in establishing a 'blended price' for oil. Consideration is given to the information that is required, given the degree of regulation that now prevails in the oil and gas industry. The danger in not having adequate cost information available is that in pursuing the objective of oil self-sufficiency we might leap over potentially cheaper sources to oil which could be more expensive or we might delay the development of alternative fuels due to a lack of cost information.

The relevance of fiscal incentives is due to their role, in addition to costs and prices, in influencing the development of future potential supplies of oil in Canada. The system of incentives, many of which operate through the federal income tax, is described. They have the effect of improving the cash position of firms in the industry and thereby the rate of return that can be realized on investment in either exploration or development.

PART I
THE BENEFITS

Chapter 2

THE CASE FOR SELF-SUFFICIENCY

John A. Dawson

Introduction

As the world depletes its remaining oil supplies, it will be difficult for Canada to remain a substantial importer. This by itself may be a sufficient reason for Canada to move towards self-sufficiency in oil. Beyond this reason, however, there have been a number of advantages claimed for Canada going in the direction of increased indigenous oil supplies rather than relying on imported oil. They include:

- avoidance of dependence on insecure foreign sources of supply;
- reduction of Canada's balance of payments deficit; and
- enhanced prospects for employment and investment in Canada.

Avoidance of Dependence on Insecure Foreign Sources of Supply

A major disruption in oil supply could be catastrophic in a modern industrial society. In Canada, oil accounts for 42 percent of our total energy consumption. The transportation sector, which accounts for more than 25 percent of our total use of energy, takes about 50 percent of the oil. Also vulnerable are the homes and businesses that rely on oil for heating in central and eastern Canada, and the electrical generating capacity in the Atlantic provinces which is heavily dependent on oil.

The risks of dependence on foreign sources of oil supply have increased as the scarcity value of remaining oil reserves has become increasingly apparent. About 80 percent of the non-Communist world's proved oil reserves are in countries that make up the Organization of Petroleum Exporting Countries, with Saudi Arabia accounting for 30 percent, Kuwait and Iran, 11-12 percent each, and Iraq and the United Arab Emirates, about 6 percent each. Venezuela accounts for about 3 percent.

In 1979, Canada's direct oil imports were at a rate of about 490 thousand barrels (78 thousand cubic metres) per day. More than three-quarters of these imports came from two of the OPEC countries, Saudi Arabia and Venezuela. Next in order of importance was Iran.

The uncertainties associated with the supply of oil, particularly from the volatile Middle East, need to be viewed against the strength of the demand for the oil. For example, United States projections indicate that, while a short-term decline in oil imports to that country may occur from 1979 to 1981, they are expected to reach a level at the end of the decade which is higher than at the beginning. In its most recent review, the International Energy Agency concluded:¹

The serious problems of adjusting energy sources and supplies to needs, that were earlier predicted for the mid to late 1980s, are with us now on a continuing basis.

Oil-importing countries obviously are in an extremely vulnerable position.

Steps can be taken by Canada to cope with short-term disruptions in oil supplies. They include such measures as: the emergency oil allocation plan of the International Energy Agency in which Canada is a participant; long-term contracts with oil exporting countries; and the stockpiling of oil. While steps along these lines are necessary to deal with potential short-term disruptions, they would not be effective in meeting long-term supply shortages. Furthermore, the effects on Canada of long-term shortages wrought through the impact on the world economy would have even more impact than the effects of the energy shortages themselves.

Weighing the risks of dependence on foreign oil and the potential impacts on the Canadian economy that would flow from supply curtailments would be a difficult exercise. If one were able to consider fully the costs associated with reliance on foreign oil, however, it is likely that oil imports would prove to be more expensive than the oil that could be produced in Canada. By mid-1980 the cost of a barrel of imported oil had risen to \$CDN 38. This appears to be higher than the cost of a number of Canadian sources that could be developed (see Chapter 4), and it does not take account of any of the additional costs associated with continued dependence on foreign supplies. It is unlikely, however, that the amounts necessary to replace oil imports could be developed quickly.

Reduction of Canada's Balance of Payments Deficit

Canada's exports are currently falling short of her imports by about \$5 billion per year. It is frequently argued that meeting more of Canada's oil requirements from domestic production will contribute to a lessening of the balance of payments deficit. It is further argued that such a move would also reduce the instability in the balance of payments that is occasioned by sharp upward movements in world oil prices.

On the matter of instability in Canada's balance of payments, it should be noted that historically there have been wide swings in the merchandise trade balance associated with the country's heavy reliance on exports of primary and semi-processed goods, for which prices and markets are less stable than for the manufactured products which we import. More recently, the increase in the current account deficit has been associated with travel and tourism and with the shift towards increasing net imports of oil. While it is evident that having a net import balance of zero in Canada's oil account would wipe out the instability due to changes in oil prices, it is not a compelling argument for oil self-sufficiency.

With respect to the general effect of increasing oil production in Canada so as to reduce oil imports, like any other change in exports or imports it will, of course, have its direct impact on the balance of trade. But it will also have ever widening rounds of indirect effects on international payments, through feedback from effects on employment, investment, the exchange rate, the money supply and so on. The temporary effects of a lessened deficit occasioned by reduced oil imports will, of course, be welcome but its later effects may not be. For example, if it results in a strengthening of the Canadian dollar in foreign exchange markets, it may weaken the position of the Canadian manufacturing industry against world competition and cause the manufacturing sector in Canada to be smaller and the deficit on foreign trade in manufactured goods to be larger. One needs to consider these broader effects on the Canadian economy, including effects on employment, the price level, productivity and the rate and direction of growth. Effects on the balance of payments are of significance only as intermediate steps in the processes by which these more basic goals are won or lost.

The experience of Norway during the 1970s is pertinent, although more extreme than potential Canadian developments. Increased oil production and exports at a time of sharp oil price increases was

pricing Norway's non-oil industries out of the market. A price and wage freeze and other measures had to be instituted to avoid disrupting the balance in the economy that Norwegians wished to retain over the longer term.²

There is no special reason from a balance-of-payments point of view that the imports and exports of any one commodity or group of commodities should be in balance and, in any event, Canada has a surplus for energy commodities as a group. The real issues are whether or not Canada has a comparative advantage in the production of oil and whether we want to accelerate production from a non-renewable resource base. If the current account balance needs improvement, as a general rule we should seek to improve it from those industries where our land, labour and capital are most productive of either exports or import-replacements.³

An additional comment about the potential exchange rate effects is necessary. The effects on the exchange rate will depend on the timing of the investments in increased oil production in relation to the flow of production and on the import content of the investments. In addition to the effects on merchandise trade and trade in services, the effect on the exchange rate will depend on whether the sources of the investment funds are Canadian or foreign. It will also depend on whether the Bank of Canada takes actions to offset the changes in foreign exchange reserves that would be altered as a result of all these transactions. Thus, the argument for increasing oil production in Canada so as to strengthen the Canadian dollar is not very convincing and, in any event, it is not clear that this is an objective that Canadians would wish to pursue.

Enhanced Prospects for Employment and Investment in Canada

If Canada's labour and capital resources were fully employed and efficiently utilized, little would be gained from stimulating economic activity through producing a commodity in Canada instead of importing it. The attempt to increase economic activity in such a situation simply pushes costs and prices up. However, Canada's labour and capital resources are not fully employed, except in Alberta. Thus, there are potential multiplier effects associated with increasing oil production in Canada.

To the extent that the primary location of increased oil production would be in Alberta, most of the short-run effects would show up as increased costs and prices. In the longer run there would

be increased activity through migration of additional workers to the province. To the extent that in both the short and longer run the activity in Alberta entails the supplying of goods and services from regions in Canada where there is unemployment, increased oil production will create jobs. The economic stimulus takes place outside of Canada, of course, if the goods and services are imported.

The development of oil production off the east coast would be especially attractive both in stimulating activity in a region with high unemployment and in the multiplier effects of this activity. In the short run there is, however, the problem of the development of skills required to shift some of the existing labour force into the new activities that occur in the region.

For each of the possible sources of increased oil production (see Chapter 4) there would be a potential stimulus to industrial activity and employment over and above the direct activity associated with the investment and operations required to produce the oil. This indirect stimulus could be significant and might be largely outside the region where the project is located. For example, it has been estimated that a \$7 billion Alberta oil sands plant like the proposed Al sands plant would generate Ontario activity and jobs leading to \$1.8 billion in extra Ontario household income.⁴ Similarly, the exploration activity in the Arctic and off Canada's eastern coast is having effects that extend far beyond the regions where the activity is located.

The regions where activity and employment growth is lagging do, however, have opportunities for economic activities located primarily within the regions and, if the issue were simply a matter of additional activity and employment, there would be a preference to go that route. Furthermore, if there were other fuel alternatives that could be developed in the oil-poor regions in competition with oil (see Chapter 5), they would be preferred because they would reduce the oil dependence of the region and at the same time create the primary as well as many of the indirect activities within the region.

There are also potential positive effects on economic activity and employment in Canada that would be derived from the assurance of continuing adequate supplies of oil. The stimulus here would stem, not from the potential multiplier effects outlined above, but from the activity that could be planned and the investment that could take place in various parts of the country if industry was assured that supply disruptions could be avoided. Thus, the Canadian Manufacturers' Association, in a submission to the federal Minister of Energy on

March 26, 1980, argued that oil pricing policy should be defined for a five-year period, with oil prices permitted to rise to 85 percent of the Chicago or international price over that period.

Summary

The case for oil self-sufficiency depends to a large extent on the weight given to risks associated with continued dependence on insecure foreign sources of supply. Our brief review suggests that they may be high. As for the balance-of-payments and exchange rate effects, the arguments are weak because the ramifications extend far beyond the initial impacts and may offset the initial benefit. The potential gains in Canadian investment and employment from increased domestic oil production could be significant. Many of these could be obtained, however, through other activities. Perhaps the most compelling argument, and one that has not been treated here, is that it will be difficult for Canada to retain the good will of other countries if this country remains a major oil importer as the world runs down its remaining oil supplies.

Footnotes

¹International Energy Agency, "The Review of Energy Policies and Programmes," (Paris: International Energy Agency, June 9, 1980), Press Release. See also F. W. Gorbet, "Energy Self-Sufficiency: A Realistic and Desirable Goal?" Canadian Public Policy, VI:3, Summer 1980.

²The Norwegian experience is treated in John C. Ausland, Norway, Oil, and Foreign Policy (Boulder, Colorado: Westview Press, 1979), Westview Special Study.

³For a further discussion of these balance-of-payments effects, see T. L. Powrie, Energy Policy and The Balance of Payments: An Outline of the Issues, (Calgary: Canadian Energy Research Institute, July 1979), Study No. 6.

⁴Presentation by H. Maciej of the Canadian Petroleum Association, to the National Conference of the Society of Management Accountants, Calgary, Alberta, July 3, 1980.

PART II

ACHIEVING OIL SELF-SUFFICIENCY

Chapter 3

PROSPECTS FOR REDUCED OIL CONSUMPTION IN CANADA

W. B. Friedenber^g and A. J. Nixon¹

Introduction

Canadian oil consumption in 1979 was at a rate of about 300 thousand cubic metres (1.9 million barrels) per day. Canada's direct imports were 78 thousand cubic metres (500 thousand barrels) per day into eastern Canada which represents about 25 percent of domestic oil consumption. The Atlantic region is entirely dependent on imports to meet its oil requirements. Quebec relies on oil imports to meet 35 percent of its requirements of 80 thousand cubic metres per day. Canada continues to export some oil to the United States, the majority being heavy oil. Exports approximated 25 thousand cubic metres per day excluding about 20 thousand cubic metres per day exported under swap arrangements.

The purpose of this chapter is to analyze Canada's prospects for reduced oil consumption between now and the year 2000. The reduction of Canada's oil consumption depends critically upon government legislation. The price of oil, the expansion of Canada's gas pipeline system, and conservation programs, three important variables influencing Canada's oil consumption, are all subject to government legislation. The findings of this chapter indicate that the growth rate of oil consumption could be slowed considerably, thereby making Canadian oil self-sufficiency a more viable proposition.

Factors Affecting Energy and Crude Oil Demand

Empirical work has revealed that price is a large determining factor of energy demand. Elasticity estimates for total energy demand are generally lower than those for the individual fuels as the availability of substitutes for energy as a whole are more limited than for any one fuel type.² Table A.1 in Appendix A illustrates elasticity estimates for total energy and specific fuel types.

Another salient factor affecting energy demand is the level of economic activity in the national economy. Although Gross National Product (GNP) is an important determining factor of the level of energy

consumption, forecasting energy consumption on the basis of an historic ratio between GNP and energy consumption is only a valid procedure under conditions of constant relative prices or non-responsiveness to changes in relative price levels. As the relative price of energy increases one would expect to observe future economic growth becoming less energy intensive. Other energy demand determinants are tastes, disposable income and its distribution, and the number of households and their spacial location.

If one were to look at the demand for a specific fuel type, particularly crude oil, one could outline its determining factors with even greater precision. Price is crucial in determining the level of consumption as well as the prices of competing fuel types such as natural gas and coal. Technology is another important determinant as it affects crude oil consumption, especially in the transportation sector where the degree of price responsiveness is relatively weak (see Table A.1).

The technological state of existing capital stock also affects crude oil demand. A specific fuel type may be 'captured' in the sense that it would not be economic to convert the capital stock so that an alternate fuel may be substituted.

The Impact of Higher Domestic Oil Prices

It is clear that if Canada's oil price is to achieve parity with the world price within the current decade, annual increments of \$2 per barrel (\$12.60/m³) will not be sufficient.

It is expected that a \$2 per barrel per year growth rate would yield a 2.5 to 3.0 percent average growth rate in oil consumption to the year 2000.³ We have chosen to call this rate the '70s Trend' forecast since it essentially extrapolates from Canada's experience during the 1970s.

The above scenario is in contrast to the NEB and EMR forecasts.⁴ (See Table 3.1). The NEB assumes that the domestic oil price will increase at \$5 per barrel (\$31/m³) per year to 1983 after which it will remain constant in real terms. The resulting average annual growth rate in oil consumption between 1978 and 2000 would be 1.2 percent. The EMR '1986 Parity' case shows that for the same period the growth rate would be 0.5 percent.

While there is a significant difference in the forecast growth rates for oil consumption between the NEB and EMR, there is little difference in the forecast of relative fuel shares. Table 3.2

TABLE 3.1
FORECAST AVERAGE ANNUAL GROWTH RATES IN OIL CONSUMPTION
UNDER HIGHER DOMESTIC OIL PRICE INCREASES
(EMR AND NEB)

	1978-1985	1978-1990	1985-1990	1990-2000	1978-2000
EMR: ^a	0.7	0.3	0.3	0.8	0.5
NEB: ^b	1.2 (1979-1985)	1.1 (1979-1985)	0.9	1.3	1.2 (1979-2000)

SOURCES: Canada, Department of Energy, Mines and Resources, Canadian Oil and Gas Supply/Demand Overview, November 1979, Table 8. Canada, National Energy Board, Reasons for Decision, November 1979, Table C-5.

^aEMR '1986 Parity' case - assumes that the domestic oil price increases by \$4/bbl per year between 1980 and 1982, and \$5/bbl per year between 1982 and 1986, after which it tracks the world price. The world oil price is assumed to increase at 2 percent above the rate of increase for the U.S. wholesale price index. The domestic price of natural gas is assumed to be maintained at its 85 percent Btu parity with oil.

^bNEB 'Medium Demand' case - assumes that the domestic oil price increases by \$5/bbl per year between 1979 and 1983 achieving parity with the world oil price by 1983. World oil price is assumed to remain constant in real terms. The domestic price of natural gas is assumed to be maintained at its 85 percent Btu parity with oil.

TABLE 3.2
PERCENTAGE SHARES OF ENERGY FUELS IN
TOTAL ENERGY CONSUMPTION
(EMR AND NEB)^a

	1979	1985		1990		2000	
	NEB	EMR	NEB	EMR	NEB	EMR	NEB
Oil	42	39	38	35	36	31	31
Gas	17	18	17	17	17	17	16
Coal	9	12	8	13	9	13	9
Primary Electricity	29	31	33	34	34	38	38
Other ^b	3	-	3	1	4	1	5

SOURCES: Canada, Department of Energy, Mines and Resources, Canadian Oil and Gas Supply/Demand Overview, November 1979, Table 8. Canada, National Energy Board, Reasons for Decision, November 1979, Table C-5.

^aFuel shares under 'EMR' are those corresponding to EMR's '1986 Parity' energy demand projections. For oil price assumptions see notes to Table 3.1.

Fuel shares under 'NEB' are those corresponding to the NEB's 'Medium Demand' case. For oil price assumptions see notes to Table 3.1.

^bIncludes solar and wood energy.

illustrates that the shares are similar except for the coal and 'other' (solar and wood wastes) categories.

To capture the impact of more rapid rates of oil price increases on oil consumption in Canada we have assumed that the domestic oil price will increase by around \$5 per barrel ($\$31/\text{m}^3$) per year to 1985, followed by increases of \$8 per barrel ($\$50/\text{m}^3$) per year to 1990. Between 1990 and 2000 the domestic price increases at the same rate as the world price (Canadian dollar import cost) which is assumed to increase at 11 percent per year from 1980 to 2000. Under these assumptions Canada's oil price will be around \$85 per barrel ($\$535/\text{m}^3$) in 1990 which is 85 percent of the \$100 per barrel ($\$630/\text{m}^3$) price for imported oil in 1990.

Table 3.3 summarizes the forecasted growth in Canada's oil consumption and the relative fuel shares under the above conditions. The average annual growth rate in oil consumption could be somewhat higher than 1.0 percent during the 1980s, i.e., between 1.0 and 1.5 percent, and during the 1990s somewhat lower, between 0.5 and 1.0 percent. Over the whole period 1980 to 2000, the growth rate remains at 1.0 percent.

Under our price assumptions oil is forecast to account for 28 percent of Canada's total energy consumption in the year 2000 as opposed to 42 percent today.⁵ Hydro and nuclear electricity (i.e., primary electricity) are forecast to account for 38 percent of Canada's energy consumption in 2000.⁶ The substitution of hydro electricity for fuel oil in Quebec as well as other parts of eastern Canada will be a contributing factor to hydro's greater share. Coal's share is forecast to be 13 percent in 2000 as opposed to 9 percent today. One of the factors contributing to this greater share will be the substitution of coal for oil in the generation of electricity in the Maritime provinces. The share for natural gas is forecast to remain constant at around 17 percent.

The reduction in Canada's oil consumption resulting from the higher oil price increases, as opposed to a continuation of the \$2 per barrel ($\$12.60/\text{m}^3$) annual increases of the late 1970s, are substantial. Table 3.4 illustrates the possible savings for 1985, 1990 and 2000.⁷

We are forecasting that Canada could save approximately 182 Mbbl/d (29 thousand cubic metres) under the higher oil price forecast as compared to the '70s Trend' forecast. (Refer to Appendix A for estimated price elasticities.) This is a substantial saving especially if it is kept in mind that it represents more than the output of an oil

TABLE 3.3
FORECAST GROWTH IN OIL CONSUMPTION AND RELATIVE
FUEL SHARES ASSUMING HIGHER OIL PRICES
(1980 - 2000)

	1980-1990	1990-2000	1980-2000	
Average Annual Growth Rate in Oil Consumption	1.0 - 1.5	0.5 - 1.0	1.0	
RELATIVE FUEL SHARES (%)				
	1979 ^a	1985	1990	2000
Oil ^b	42	35	32	28
Gas	17	17	17	16
Coal	9	12	13	13
Primary Electricity	29	33	34	38
Other ^c	3	3	4	5
	100	100	100	100

^aCanada, National Energy Board, Reasons for Decision,
November 1979, Table C-5.

^bIncludes liquified petroleum gases (LPG).

^cIncludes solar and wood energy.

Assumptions:

- (i) The domestic oil price increases by around \$5/bbl (\$31/m³) per year to 1985, followed by increases of \$8/bbl (\$50/m³) per year to 1990. Between 1990 and 2000 the domestic oil price increases at an average annual rate of 11 percent.
- (ii) The world oil price (Canadian dollar import cost) increases at an average rate of 11 percent per year from 1980 to 2000.
- (iii) Real GNP grows at an average annual rate of 3 percent between 1980 and 2000.

TABLE 3.4
POSSIBLE SAVINGS IN OIL CONSUMPTION
THROUGH HIGHER OIL PRICE INCREASES
1965, 1990 AND 2000
(Mbb/d)

<u>1985 Oil Consumption</u>		
a) '70s Trend' Forecast	2,196	
b) 'Higher Oil Price' Forecast	2,014	
1985 Oil Savings		182
1980-1985 Accumulated Savings		226,500
<u>1990 Oil Consumption</u>		
a) '70s Trend' Forecast	2,486	
b) 'Higher Oil Price' Forecast	2,114	
1990 Oil Savings		371
1986-1990 Accumulated Savings		534,905
<u>2000 Oil Consumption</u>		
a) '70s Trend' Forecast	3,184	
b) 'Higher Oil Price' Forecast	2,335	
2000 Oil Savings		850
1991-2000 Accumulated Savings		2,252,894
1980-2000 Accumulated Savings		3,014,347

NOTE: The 1979 base is taken to be 1,894 Mbb/d. The '70s Trend' forecast assumes a 2.5 percent average annual growth rate (AAGR) in oil consumption throughout the whole period 1979-2000.

For the assumptions to the 'Higher Oil Price' forecast see the note to Table 3.3.

See Table B.1 in Appendix B, which is this table reproduced in thousands of cubic metres per day.

sands plant at full capacity (125 to 140 Mmbl/d). By the year 2000 the savings in oil consumption amount to 850 Mmbl/d.

Perhaps of greater significance are the accumulated savings in oil consumption if Canada reduced its growth rate in oil consumption from the recent historical rate of 2.5 percent to 1.0 percent. Comparing the '70s Trend' forecast to the 'higher oil price' forecast in terms of accumulated oil savings, Table 3.4 shows that over the 21 years, 1980 to 2000, the total savings would be 3,015 million barrels (479 million cubic metres). These savings represent approximately 45 percent of Canada's remaining established reserves as of the end of 1978. Looked at in this manner, the addition to Canada's supply of oil reserves in the year 2000 made possible by reduced rates of growth in oil consumption due to higher annual rates of oil price increases is certainly substantial.

Natural Gas Pipeline Extension

The expansion of the natural gas pipeline system is another avenue by which Canada could reduce its oil consumption. There are two proposed expansions scheduled for the 1980s: the Maritime extension and the extension to Vancouver Island.

The November 1979 NEB gas export report projected gas sales for the expanded market areas of Quebec, the Maritime provinces, Vancouver Island, Manitoba and Ontario. Table 3.5 illustrates the savings in oil consumption due to expanded natural gas sales. It is assumed that the additional gas sales are totally at the expense of oil consumption.

TABLE 3.5

SAVINGS IN OIL CONSUMPTION DUE TO
NATURAL GAS MARKET EXPANSION
(Mmbl/d)

<u>1985</u>	<u>1990</u>	<u>2000</u>
88	132	189

SOURCE: Canada, National Energy Board, Reasons for Decision, November 1979, Table C-5.

Government Legislated Conservation Programs

Public policy measures designed to achieve conservation must be evaluated according to their cost-effectiveness. If an energy conservation program costs more to administer than the value of the benefits earned by conserving the energy, the program is not cost-effective.

Table 3.6 outlines several conservation schemes which have energy conservation potential for the Canadian economy. In this table we have used the energy conservation forecasts of the Department of Energy, Mines and Resources in its 1977 Energy Conservation report. The forecast assumes that governments legislate and enforce the full programs immediately.

In the residential sector there are three broad measures which account for the estimated annual energy saving of 306×10^{15} joules or 8 million cubic metres (50 million barrels) of crude oil equivalent by 1990. Adding insulation to existing homes (under the Canadian Home Insulation Program), and the adoption of improved energy efficiency standards for new homes (through stricter building codes) as well as existing homes (through improved maintenance, retrofitting furnaces and temperature set back)⁸ are the energy conservation measures contributing to the predicted energy saving in this sector. Extending these conservation measures into the commercial sector would result in an annual energy saving of 443×10^{15} joules or 11 million cubic metres of crude oil equivalent (69 million barrels). The transportation sector appears to have a large energy saving potential with 759×10^{15} joules or 20 million cubic metres of crude oil equivalent by 1990 (126 million barrels). The program denoted 'intra-modal substitution' refers to energy savings coming from substituting among different types of road transport (i.e., increased use of car pools) as opposed to substituting between different modes of transport (i.e., rail for truck transport) which has been termed 'inter-modal substitution' in the context of Table 3.6.

Worth noting from Table 3.6 is the absence of any conservation scheme expected to be implemented in the industrial sector. Over the forecast period (1980-2000) energy conservation in this sector is expected to occur as a result of the response to higher prices, but not as a result of the adoption of specific conservation measures per se. This is not a surprising conclusion since industries, as profit maximizers, would find it in their best interests to respond as rapidly as possible to market signals such as higher prices.

TABLE 3.6
CONSERVATION PROGRAMS AND POSSIBLE ENERGY
SAVINGS IN THE CANADIAN ECONOMY

Programs	Energy Savings Per Annum (10 ¹⁵ joules)	
	by 1985	by 1990
Total in the Residential Sector:	316	306
Reinsulation of existing homes		
Adoption of improved energy efficiency standards for new homes		
Improved heating system efficiency, improved maintenance, retrofitting of existing furnaces, temperature set back		
Total in the Commercial Sector:	316	443
The adoption of the three programs outlined above for the residential sector plus improved techniques in building operation and maintenance		
Total in the Transportation Sector:	485	759
Improved car performance standards		
Inter-modal substitution		
Intra-modal substitution		
Total Annual Energy Savings	1,117	1,508

SOURCE: Canada, Department of Energy, Mines and Resources, Energy Conservation In Canada: Programs and Perspectives (Ottawa: Department of Energy, Mines and Resources, 1977), Report EP 77-7.

Using the forecast relative fuel shares (see Table 3.3) for the years 1985, 1990 and 2000, the proportion of total energy savings from Table 3.6 which could be accounted for by reductions in the demand for crude oil were calculated. The calculated savings in crude oil consumption are reported in Table 3.7.

TABLE 3.7
POSSIBLE SAVINGS IN CRUDE OIL
CONSUMPTION DUE TO CONSERVATION MEASURES
1985, 1990, 2000
(Mbbl/d)

<u>1985</u>	<u>1990</u>	<u>2000</u>
176	214	189

It would appear that the ability of energy conservation programs to reduce crude oil consumption is substantial. In the first five years of the forecast period, crude oil savings due to government legislated conservation measures will have reached 176 thousand barrels (28 thousand cubic metres) per day, which is greater than the combined output of the Syncrude and Suncor plants at their current levels of production. Viewed alternatively, these savings have the potential of reducing our current level of oil imports (approximately 500 thousand barrels per day) by approximately 35 percent. This potential ability to replace imports, of course, is dependent upon the ability of the transportation system to move more crude oil to Quebec and the Maritime provinces.

Comparing the oil savings made possible by specific conservation measures (see Table 3.7), higher oil prices (see Table 3.4), and the expansion of the gas pipeline system (see Table 3.5), it is evident that a large saving potential in the earlier years lies with conservation. The largest crude oil saving potential, however, rests with higher oil price increases in the latter part of the forecast period. This is because the results of conservation programs are assumed to be obtained quickly but there are time lags in the area of price response. In the year 2000, higher oil prices account for crude oil savings of

850 thousand barrels per day, compared to 189 thousand for conservation. Thus, as consumers have time to adjust to the higher prices for crude oil, savings are realized.

Summary and Conclusion

Table 3.8 shows possible savings in oil consumption due to higher oil prices, gas pipeline expansion and government legislated conservation measures. In total, Canada could save about 447 thousand barrels per day of crude oil in 1985, rising to 1,227 thousand in 2000. The total savings estimate of 447 thousand barrels per day in 1985 may be optimistic since it is contingent upon the government legislating such conservation measures. These measures comprise a smaller proportion of total crude oil savings between 1990 and 2000, hence there would be less upward bias from possible over optimism in the area of conservation measures.

TABLE 3.8
SAVINGS IN CANADIAN OIL CONSUMPTION
1985, 1990, 2000
(Mbb1/d)

Year	Impact of Higher Oil Prices	Expansion of Gas Pipeline System	Government Legislated Conservation Measures	Total
1985	182	88	176	447
1990	371	132	214	717
2000	850	189	189	1,227

Figure 3.1 illustrates levels of Canadian oil consumption forecasted under the different oil conservation assumptions. The numbers in brackets show average annual growth rates (AAGR) from 1979. The '70s Trend' forecast shows oil consumption growing at an AAGR of 2.5 percent to 2000. The impact of higher oil prices is forecast to reduce the growth rate to 1.0 percent. The addition of natural gas pipeline expansion reduces the average annual growth rate estimate to 0.6 percent. Finally, if we include the forecast savings from government legislated conservation measures in 2000, the overall growth rate in oil consumption is reduced to 0.2 percent.

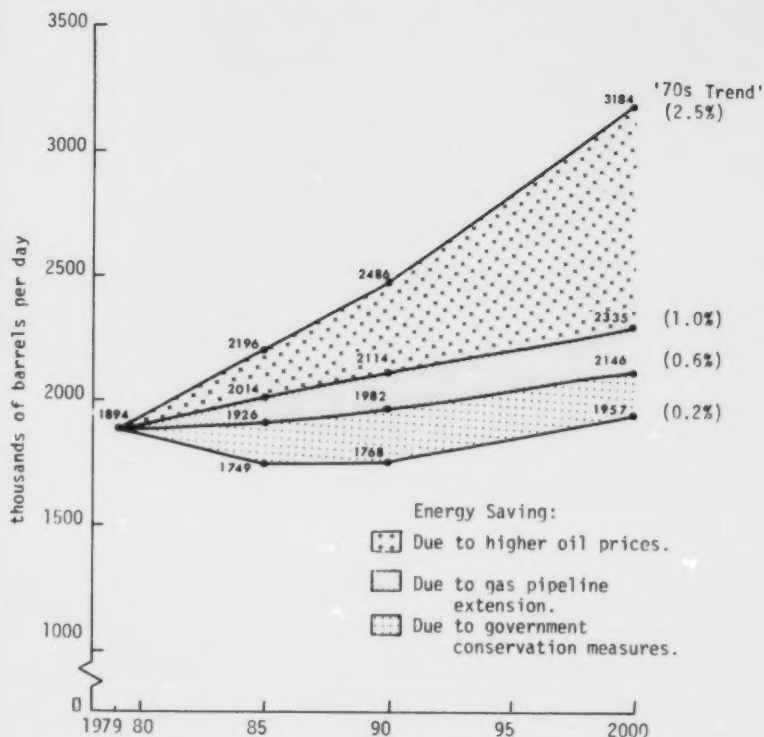


FIGURE 3.1: Forecast Levels of Oil Consumption, 1979-2000

NOTE: The figures in parentheses denote the average annual growth rates for oil consumption under the various scenarios.

Looking at the intermediate year 1990, the combined impact of higher oil prices and gas pipeline expansion is forecast to bring the growth rate down from 2.5 percent under the '70s Trend' forecast to approximately 0.5 percent. The addition of government conservation measures could result in 1990 oil consumption being less than 1979 consumption, resulting in a negative growth rate over the eleven years.

Figure 3.2 shows the relative fuel shares in 1979 and the forecast of fuel shares in 2000 assuming higher oil prices, gas pipeline expansion and government legislated conservation measures.⁹ Oil is forecast to account for 26 percent of total energy consumption in 2000 compared to about 42 percent at present.¹⁰

It is important that Canada allows its domestic oil price to increase at a rate considerably above \$2 per barrel per year if oil is to account for 26 percent of total energy consumption in 2000. The relative importance of higher oil prices contributing to lower growth in oil consumption is evident from Figure 3.1.

The price mechanism is an efficient allocator of Canada's scarce oil reserves and is the mechanism upon which considerable reliance should be placed before legislating specific measures designed to reduce oil consumption. A higher oil price has the dual advantage of increasing domestic supply while restricting domestic demand.¹¹ The net result is less dependence on imported oil and thus a step towards oil self-sufficiency.

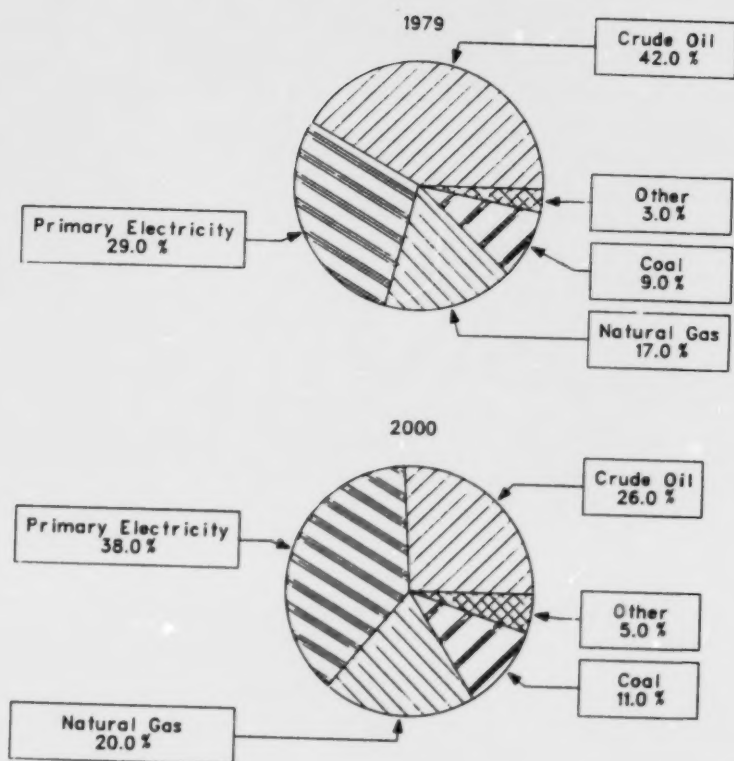


FIGURE 3.2: Relative Fuel Shares, 1979 and 2000

NOTE: 1979: National Energy Board, Gas Export Report, November 1979, Table C-5.

2000: Consideration has been given to 1) higher oil prices, 2) gas pipeline expansion, and 3) government initiated conservation measures as discussed in this paper.

Footnotes

¹Summary by Eric A. Howling of W. B. Friedenbergl and A. J. Nixon "Prospects for Reduced Oil Consumption in Canada" (Calgary: Canadian Energy Research Institute, May 1980), Working Paper 80-4.

²The own-price elasticity of demand equals:

$$\frac{\% \text{ change in quantity of good demanded}}{\% \text{ change in price of good}}$$

The own-price elasticity shows the percentage change in the quantity of the good demanded given a one percent change in its price.

³Implicit in this expectation is a forecasted growth rate for real GNP averaging 3 percent and an inflation rate of approximately 9 percent.

⁴The NEB and EMR forecasts shown in Table 3.1 assumed parity with world oil prices (as projected when the forecasts were made) by 1983 and 1986 respectively. Given that imports currently cost about \$35/bbl (\$220/m³) and the domestic price is about \$16.75/bbl (\$105/m³), a domestic price increasing at \$5/bbl (\$31/m³) per year in combination with the import price increasing at 11 percent per year (2 percent above Canada's rate of inflation) would never result in parity but rather a further widening of the two prices.

⁵The NEB in its November 1979 gas export report forecast oil consumption to account for 31 percent of total primary energy consumption in 2000 (medium demand case). This figure agrees with that produced by EMR under the '1986 Parity' case. W. Brent Friedenbergl Energy in Canada: Review and Outlook to 1995 (Calgary: Canadian Energy Research Institute, July 1979), Study No. 5, forecasts oil consumption to account for 29 percent of Canada's primary energy consumption in 1995.

⁶Referring to the above footnote (f.n. 5) the comparable percentage figures between NEB, EMR, and Friedenbergl are 38, 37 and 37 percent respectively for primary electricity.

⁷Throughout this chapter the term 'savings in oil consumption' is used in place of the term 'reduction in oil consumption'. Since oil is a depletable natural resource a reduction in oil consumption today has the effect of saving oil for future consumption.

⁸The required temperature set back necessary to achieve the energy savings estimated under this program would be 18°C at night and 21°C during the day.

⁹We expect the demand for total energy to grow at an average annual rate of 2.5 percent over the period 1980 to 2000.

¹⁰The projections contained in this chapter make no allowance for the possibility of consuming oil derived from coal liquefaction. To the extent this becomes possible before the year 2000 there will be savings in Canada's consumption of conventional oil reserves. Coal liquefaction is becoming a stronger possibility as oil prices continue to rise.

¹¹Implicit in this statement is that higher revenues are realized by producers, and consumers are not subsidized to the extent of the price increase.

Chapter 4

FUTURE SUPPLIES OF OIL IN CANADA AND THEIR COSTS

Z. Charles Slagorsky¹

Introduction and Main Conclusions

The purpose of this chapter is to assemble the available information about the sources of future Canadian supplies of oil and their respective costs.

Five types of oil production are considered:

- i) conventional
- ii) frontier
- iii) oil sands
- iv) heavy oil
- v) enhanced recovery

Estimates of future supplies are presented in Table 4.1 showing five-year intervals between 1980 and 2000. This table is shown in metric units as Appendix Table C.1. A brief discussion of the five sources of oil will outline some of the uncertainties and problems peculiar to each of the five categories. Estimates of costs are also discussed.

The primary conclusion of this chapter is that if the average prediction of future supply is fulfilled, other things unchanged, Canada will not reach complete self-sufficiency in oil between now and the end of this century. It has been found that if taxes and royalties are considered, all but conventional oil production is uneconomic relative to a Canadian price of oil of \$17.75 per barrel. For the objective of oil self-sufficiency this has a perverse effect. An artificially low price encourages greater consumption while at the same time provides no incentive for increased production. The objectives of keeping the Canadian price of oil from rising, and displacing all or a part of the imported oil by increased domestic production, are clearly not compatible.

TABLE 4.1
ESTIMATED OIL PRODUCTION FROM VARIOUS SOURCES
(thousands of barrels per day)

	(i)	(ii)	(iii)	(iv)	(v)		
					Enhanced Recovery		
	Conventional Oil	Frontier Oil	Oil Sands	Production	Heavy Oil Upgrading	Light & Med. Oil	Heavy Oil
1980	1,313 (1,230-1,343)	-	162 (150-188)	230 (88-230)	-	12(?) (8-24)	3 (0-8)
1985	824 (702-910)	90 (0-260)	238 (200-260)	161 (80-230)	50 (?)	75 (17-174)	26 (4-87)
1990	752 (564-1,093)	453 (0-1,100)	541 (500-625)	176 (78-271)	75 (50-100)	210 (30-550)	53 (13-105)
1995	593 (396-945)	500 (0-?)	795 (708-975)	191 (85-304)	100 (50-150)	148 (19-346)	70 (21-126)
2000	150 (?)	(?)	898 (815-944)	170 (90-287)	(?)	27 (?)	135 (0-266)

NOTE: This table is reproduced in metric units as Appendix Table C.1.

General Comments

It should be stressed at the outset that both the supply and the cost figures presented here are estimates and that they should, therefore, be interpreted cautiously.

While supply estimates will be shown for five-year intervals between 1980 and 2000, cost data are shown only for 1980. This is because all costs (unless stated otherwise) are expressed in constant 1980 Canadian dollars and are, therefore, still pertinent for application to subsequent years.

It should be pointed out that the oil producers' cost may rise at a faster rate than the national income deflator due to bottlenecks in the labour and material markets. A second inflationary factor is that the cost of finding new oil increases over time.²

It is convenient to view the cost per barrel as the supply price a producer must receive to undertake production, with producers recovering a portion of the total finding cost as well as development and production costs over each barrel produced, regardless of whether it is produced now or in the future. The supply price estimates that are made in this study do not include taxes or royalties, and are basically wellhead prices or, in the case of oil sands plants, prices at the plant gate.³

Table 4.1 shows the estimated potential future oil production from the five sources under consideration. The estimates are based on established reserves and on projected reserve additions. In Table 4.1, a single number has always been chosen as an estimate with the range indicating possible low and high extremes shown in brackets. The range shows the actual spread of the collected estimates; and the single figure (to represent a 'base' case) has been calculated as the simple average of all estimates except in the case of older estimates (more than three years), when more recent information was made to carry more weight.⁴ Where no estimates or only single estimates were available, a question mark appears in the table to warn the reader of increased uncertainty.

Conventional Oil

Two salient features of conventional light and medium oil production in the western Canadian sedimentary basin are the low discovery rate of new oil reserves and the declining production rates from existing reservoirs using primary and secondary recovery processes. Since natural gas carries a lower royalty rate than oil, and producers

have shared in profitable export contracts where the price of gas is tied to the world price of oil, many companies have until recently found the production of natural gas more attractive than exploration for oil. Figure 4.1 compares rates of production and discovery of oil and natural gas during the 1970s. Even at the current Canadian domestic price of oil (\$17.75/bbl), with the finding cost at the \$8.00 per barrel level reached in 1979,⁵ there would be only a small profit margin left after taxes and royalties were paid even if the search for oil was successful.

Finding costs have varied annually, the 30-year Canadian average for the period prior to 1977 being \$1.66 per barrel equivalent in current dollars. The possibility of smaller reservoirs becoming increasingly more difficult to find implies that this component of the supply price of oil may increase in the future.

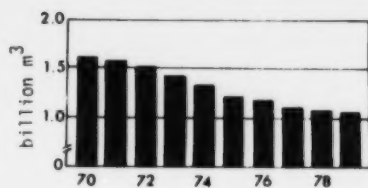
Estimates of future supply and production of conventional oil are largely uncertain because we are unsure of how oil producers would react to an increased domestic oil price and how successful any increased exploration would be. It is clear, however, that a higher price will tend to increase the production of oil in three ways:

- i) the percentage of oil in place recovered would increase through the application of improved levels of recovery;
- ii) oil could be recovered from previously non-commercial discoveries; and
- iii) new reserves could be found through successful exploration.

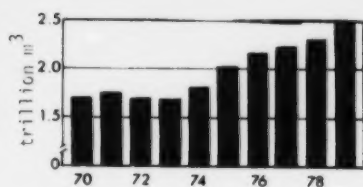
The supply estimates in the first column of Table 4.1 indicate that conventional oil production is expected to decline throughout the forecast period.⁶ The projected volumes of production using the extreme figures from the brackets in Table 4.1 are shown in Figure 4.2. It is clear that no matter which figures are used, the trend of future production is declining and only a truly major oil discovery could reverse it.

The supply price of the conventional oil has been estimated at \$11.41 per barrel with possible extreme values of \$7.78 and \$15.04 per barrel (Table 4.2). This table is shown in metric units as Appendix Table C.2. This wellhead price is composed of three parts: the finding cost, the development cost, and the production or lifting cost. The most recent estimates of finding cost vary between \$5.00 and \$8.00 per barrel. Estimates of development cost, which include development

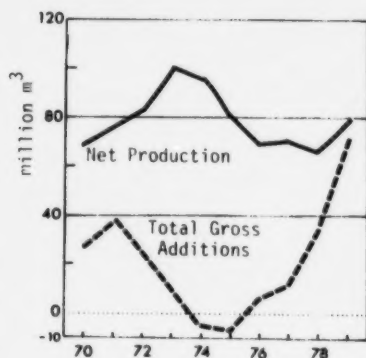
Remaining Recoverable
Crude Oil Reserves:



Remaining Recoverable
Marketable Gas Reserves:



Oil Supply:



Gas Supply:

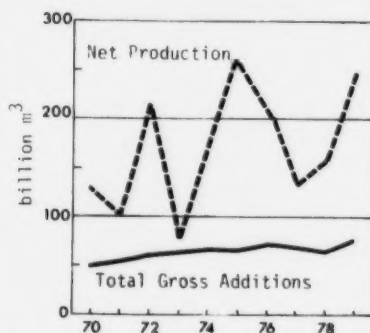


FIGURE 4.1: Production and Additions to Oil and Natural Gas, 1970 - 1979.

SOURCE: Canadian Petroleum Association, CPA Statistical Handbook. 1980, Tables 4 & 6, Section II.

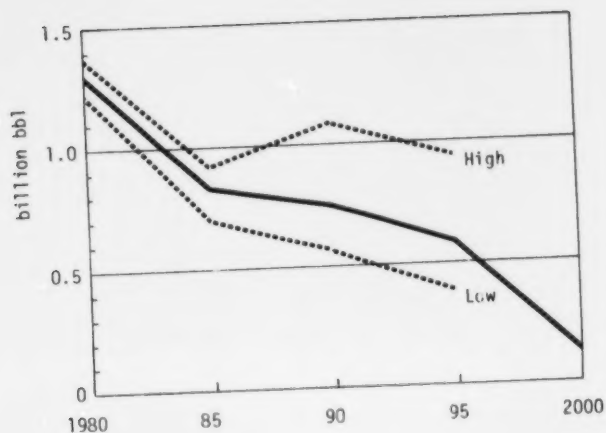


FIGURE 4.2: Estimated Future Production of Conventional Oil, 1980-2000. (High, low and average estimates)

SOURCE: Table 4.1.

TABLE 4.2
ESTIMATED SUPPLY PRICES OF OIL FROM VARIOUS SOURCES
(1980 \$/bbl)

Type of Oil	Supply Price	
	Base Case	Low and High
i) Conventional oil	11.41	7.78 - 15.04
ii) Enhanced recovery		
Light & medium oil	5.00 - 16.97	5.00 - 16.97
Heavy oil	7.62	5.57 - 11.66
Upgraded heavy oil	13.22	11.17 - 17.26
iii) Heavy oil		
Production	8.95	6.55 - 12.65
Upgrading	5.60	2.37 - 9.03
Upgraded heavy oil	14.55	12.15 - 18.25
iv) Oil sands	17.08	12.50 - 20.29
v) Frontier oil	15.50	12.40 - 18.60

NOTE: This table is reproduced in metric units as Appendix Table C.2.

drilling, land acquisitions and rentals, range between \$1.66 and \$3.70 per barrel; and those of production cost appear to fall within \$1.12 and \$3.34 per barrel.⁷

The range of supply prices given in Table 4.2 was derived by adding the corresponding ranges of all three cost components. With \$7.78 and \$15.04 thus obtained, a simple mean of \$11.41 was chosen to represent the base case. The estimates of finding cost are expressed in current dollars which means that the supply price (\$11.41/bbl) will apply more appropriately to oil being discovered now and in the future, while the lower historical finding cost of conventional oil would yield a supply price of between \$6.08 and \$10.34 per barrel for oil discovered in the past.

Frontier Oil

Oil from the frontier areas, in particular the Beaufort Sea, the High Arctic and the areas off the East Coast, will undoubtedly play an important role if Canada is to become self-sufficient in oil production. Since no oil for commercial purposes has been produced thus far, both cost and supply estimates are uncertain. Table 4.1 illustrates that in 1985 it is assumed that 90,000 barrels per day will be produced (60,000 bbl/day from the Hibernia field and 30,000 bbl/day from the Beaufort Sea) with the possibility of an additional 170,000 barrels per day from either off the coast of Newfoundland or the Beaufort Sea. By 1990, as much as 900,000 barrels per day has been predicted to flow from the Beaufort Sea.⁸ This date is tentative, however, since, depending upon the geography and the nature of the hydrocarbon in the frontier regions, three to fifteen years may be required from the date of discovery to the date of first production.

As with conventional oil, the supply price of frontier oil will have three components:

- i) the cost of finding the oil;
- ii) development drilling and rental charges; and
- iii) the cost of actual production.

The average finding cost for frontier crude oil, natural gas and gas by-products, expressed in terms of oil equivalent, for the period 1947-1977 has been estimated at \$1.47 per barrel. The average between 1973 and 1977 for 'North Canada', however, was \$2.16 per barrel equivalent and in 1977, \$4.02 per barrel.⁹

The wellhead supply price from either the Beaufort Sea or off the East Coast could be in the neighbourhood of \$15.00 per barrel. Adding and subtracting 20 percent from this figure (to obtain possible low and high extremes) yields a possible range for this supply price of \$12.40 to \$18.60 per barrel (Table 4.2).

The cost of bringing frontier oil from the producing to the consuming areas is much more significant than in the case of conventional oil. The cost per barrel of oil brought to Toronto from off-shore Newfoundland via conventional oil tanker and pipeline has been estimated to be between \$1.05 and \$2.70, depending mainly on the size of the tankers and the length of yearly operating time. The cost of delivering Mackenzie Delta-Beaufort Sea oil to either Toronto or Montreal via an ice-breaking tanker, on the other hand, could be between \$4.40 and \$6.15 per barrel. These costs can be compared to the pipeline tariff of about \$0.85 per barrel between Edmonton and Toronto.

At the present time, frontier oil is uneconomic (i.e., \$15.50 plus a transport tariff of, say, \$1.85 per barrel of oil from the offshore of Newfoundland yields a supply price, without taxes and royalties, of some \$17.35 per barrel) as compared with the domestic wellhead price of \$17.75 per barrel. It is, however, less costly than imported oil at \$CDN 30.00 per barrel to \$43.00 per barrel.¹⁰

The Oil Sands

Although oil from the oil sands is more expensive than conventional oil, supplies from such sources can be more accurately predicted since supply from an oil sands plant does not decline later in its operating life as is inevitably the case with conventional oil production.

There are, however, several problems standing in the way of rapid oil sands development. Front-end costs are much higher than in the case of conventional oil production, lead times are long, the optimal scale of projects is much greater, the technology of separating the oil from the sand is energy intensive and there are accompanying environmental problems to consider.

The anticipated future supplies from the oil sands can be seen in Table 4.1. The supply figures reflect the progress in the construction of new plants and expected extensions of plants which either already exist (Suncor, Syncrude) or are at the advanced planning stage (Alsands, Imperial Oil). These figures are uncertain to the extent

that they depend heavily on the negotiations between the operators and the two levels of government (provincial and federal) determining the tax and royalty payments and the price at which the oil will be sold.

Recent estimates of the cost per barrel of oil from the Alsands and Cold Lake projects have been \$17.10 and \$17.75 respectively.¹¹ An important aspect of these costs or supply prices is the selection of the optimal plant size so as to minimize the unit cost. NEB submissions indicate that 130,000 to 140,000 barrels per day would be optimal with likely increments of 60,000 to 70,000 barrels per day. An optimal plant size would then consist of two or three independent units, each with an output of around 65,000 barrels per day.¹²

The cost estimates provided here must be viewed with uncertainty because of the possibility of overlapping project construction periods which might cause serious shortages in the labour and materials markets, thereby inflating their respective prices.

The pricing of synthetic crude oil in Canada has recently become a contentious issue. The 'Winnipeg Agreement' of February 1975, which insured the continuation of the Syncrude project, provided a guarantee for the operators that Syncrude's output would be sold at a world price, defined as the cost of imported oil landed at Montreal, plus a quality differential.¹³ The federal government agreed to compensate refineries using synthetic crude oil as feedstock for the difference between the domestic wellhead price and the prevailing world price. This subsidy was financed by the 'Syncrude Levy' on all oil products sold in Canada which by fall of 1980 stood at \$1.75 per barrel.¹⁴

On March 29, 1980, the federal government invoked the 'force majeure' clause which effectively cancelled the world price guarantee. It was subsequently replaced by the 'reference price' for synthetic crude oil included in the proposed National Energy Program, where this price was set (effective January 1, 1981) at the lesser amount of \$38 per barrel (escalated annually by the Consumer Price Index), or the world price of oil.¹⁵

Heavy Oil

As in the case of the oil sands, the process of unlocking the heavy oil is uncertain and expensive. In order to arrive at a product (refinery feedstock) comparable to conventional oil, heavy oil must first be extracted and then upgraded which adds to the overall unit

cost. Of the approximately 230,000 barrels of heavy oil produced per day, some 120,000 barrels are exported to the U.S. where refinery capacity exists. There are no upgrading plants in Canada to date although several pilot projects are currently in progress.

From past upgrading proposals it appears that a plant consisting of one or two independent units, each producing between 45,000 and 50,000 barrels per day of upgraded oil, might be approaching size optimization.¹⁶ Studies suggest, however, that the capital cost per barrel of a 50,000 barrel-per-day plant would likely be between 15 and 25 percent higher than that for a 100,000 barrel-per-day plant.¹⁷

The production estimates in Table 4.1 are based on projections made by the NEB, ERCB, Alberta Petroleum Marketing Commission and industry sources. They include production from existing reserves and expected discoveries extracted through primary recovery and waterflood.

NEB, EMR and industry have estimated the cost per barrel of produced, but not upgraded, heavy oil to be between \$6.55 and \$12.65.¹⁸ From this range a simple mean of \$8.95 per barrel was chosen to represent the base case. This is somewhat less than conventional crude which has a higher finding cost.

Upgrading estimates vary between \$2.37 and \$9.03 due to the variations in both the capital and operating cost of the over eight upgrading processes which could be employed.¹⁹ The base case figure for upgrading heavy oil is \$5.60 per barrel. When this cost is added to the production cost (\$8.95/bbl), a base case estimate of \$14.55 per barrel of upgraded heavy oil is obtained. This is below the current Canadian oil price of \$17.75 per barrel, but since the supply price does not include taxes or royalties, the production of upgraded heavy oil appears to be uneconomic at present.²⁰

Enhanced Recovery

Enhanced recovery is defined here as all recovery methods beyond primary and secondary production. Enhanced recovery is therefore taken to include all tertiary recovery methods such as miscible gas, chemical or thermal, but not secondary methods such as waterflood. The forecasting of supply and costs is difficult since producers can skip secondary recovery or move back and forth between enhanced and primary recovery. The method is dictated by the geological conditions

of each reservoir and so it may be difficult to correctly estimate the incremental amounts of recovered oil attributable to enhanced recovery as well as the cost such recovery will entail. For this reason the supply estimates may be conservative.

Although the quantity of heavy oil reserves is very large in Canada, primary production methods will typically recover only between 3 and 5 percent of the oil. Application of waterflood will increase this percentage to between 7 and 11 percent while tertiary recovery may result in a 30 percent recovery rate.²¹ For conventional light and medium oil reserves, the recoverable amount by primary and secondary methods averages about 32 percent. This may be increased to between 40 and 44 percent by the application of tertiary recovery methods.²² The estimates of potential future oil production from enhanced recovery of both light and medium oil, and of heavy oil are shown in Table 4.1.

Much of the difference in supply estimates originates in the way future oil prices are expected to change and in the cost projections for enhanced recovery schemes. Figure 4.3 shows one estimate of the expected impact of price on enhanced recovery potential in Canada. Prince has suggested that, compared with the roughly unitary elasticity of supply of conventional oil, enhanced oil recovery is about twice as responsive to price increases.²³ Based on existing reservoirs only, he asserts that the maximum recovery potential in Canada is limited to 3.1 billion barrels and that a greater recovery would require basic technological advancement of the various processes currently in use.²⁴

For enhanced recovery of light and medium crude oil, estimates of lifting costs vary between \$5.00 and \$16.97 per barrel.²⁵ In the case of heavy oil, when taking an average of all lifting cost estimates (\$7.62/bbl) and adding to it the similarly chosen cost of heavy oil upgrading (\$5.60/bbl), we arrive at a possible base case supply price of \$13.22 per barrel of light crude oil equivalent.²⁶ Although this is below the current Canadian price, no taxes or royalties are included and thus, for the purpose of this example of base case estimates at least, the economic viability of production would depend on the taxes and royalties producers would be required to pay.

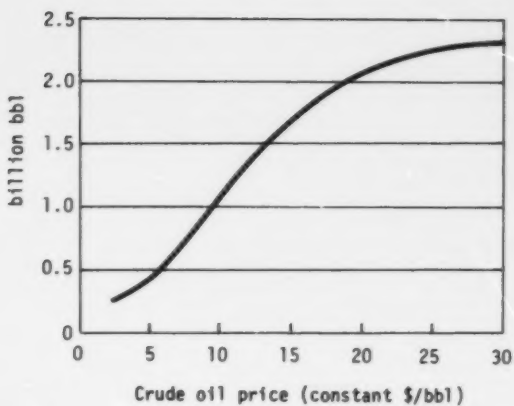


FIGURE 4.3: Impact of Price on Tertiary Recovery Potential

SOURCE: National Energy Board, Canadian Oil Supply and Requirements, 1978, p. 28.

Summary Comment

This chapter has brought together available estimates of both supplies of oil from five different sources and their respective costs. The results have been summarized in Tables 4.1 and 4.2.

The projected future supplies from the five sources from Table 4.1 can be added and compared with a demand forecast for the same time horizon to find out when self-sufficiency might be achievable. (The demand forecast, with a rate of increase in oil consumption of 1 percent per year, corresponds to the demand projection in Chapter 3 with price increases of \$5/bbl to 1985 and \$8/bbl to 1990 and 11 percent per annum after 1990.) This is done in Figure 4.4. It can be seen that, given the supply scenario from Table 4.1, only the high case forecasts Canadian oil self-sufficiency between 1986 and 1997. This time period could be extended if during self-sufficiency the excess to domestic consumption was stockpiled rather than exported. Should the base case projection come true, then only about 61 percent self-sufficiency will be achieved by 1985 and a maximum of 92 percent by 1990 and 1995 with the percentage then declining. The low case presents a rather unpleasant prospect for the objective of self-sufficiency.

The main purpose of Table 4.2 is to bring together the available cost information and attempt to rank the various alternatives. Using the base case, or average estimates, conventional oil appears to be the cheapest to supply (\$11.41/bbl), while oil from the oil sands is the most expensive (\$17.08/bbl). Oil from enhanced recovery of light and medium oil appears comparable to upgraded heavy oil, both of which are only slightly more expensive than primary and secondary recovery of conventional oil, but cheaper than frontier oil and oil from the oil sands. Therefore, given the average supply price estimates, conventional oil followed by oil obtained from enhanced recovery schemes and upgraded heavy oil should be the first sources to be tapped before oil from the oil sands and the frontier regions are brought on stream.

Given the low and high extremes, however, the cost-ranking is not as simple since many of the specified cost-ranges overlap. Nevertheless, it is still clear that the oil sands and frontier oil appear to be the most costly sources, and that there is at least the possibility of upgraded heavy oil or oil from enhanced recovery being slightly cheaper than conventional oil.

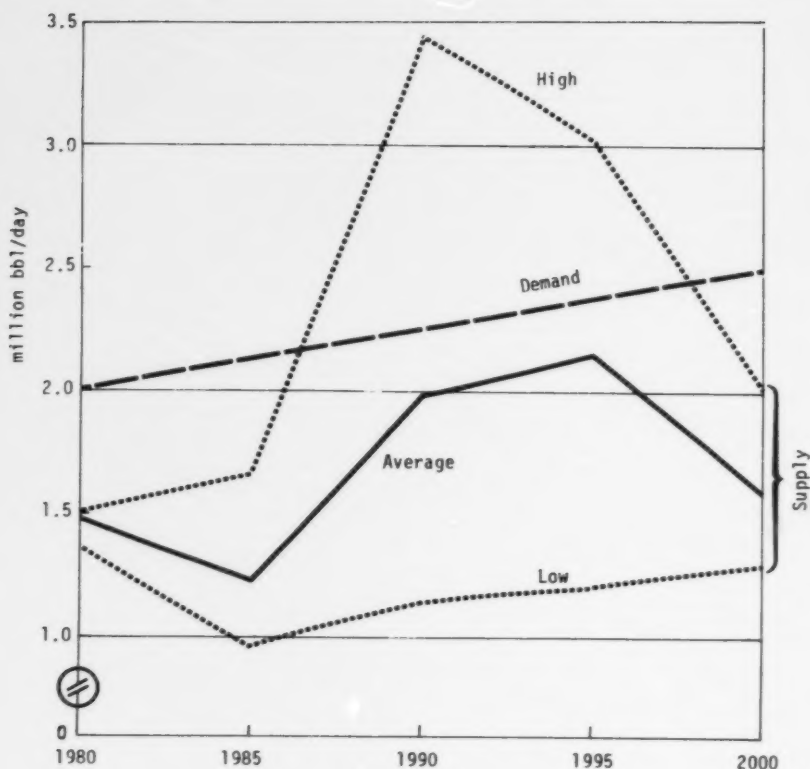


FIGURE 4.4: Canadian Oil Supply and Demand Projections

SOURCE: Table 4.1. Demand projection is adopted from NEB, Gas Export Report, 1979 (the medium demand case, growing at the rate of 1 percent per year).

NOTE: Only upgraded heavy oil is included in supply projections.

A further observation which can be made in Table 4.2 is the comparability of supply prices of upgraded heavy oil from enhanced recovery and of upgraded heavy oil from primary and secondary production. The base case prices differ by \$1.33 per barrel with the supply price of the oil from enhanced recovery being lower. One reason for this is that enhanced recovery produces more of the oil in place and therefore, although more expensive, the costs are spread over a greater number of barrels recovered, which lowers the supply price.

Footnotes

¹Summary by Eric A. Howling of Z. Charles Slagorsky, "Alternative Future Supplies of Oil in Canada and Their Costs," (Calgary: Canadian Energy Research Institute, May 1980), Working Paper 80-3.

²R. Uhler, Oil and Gas Finding Costs (Calgary: Canadian Energy Research Institute, Sept. 1979), Study No. 7.

³Although a supply price should be sufficiently high to allow an attractive return to the producer after allowance for royalties and taxes, it is possible to add the values of taxes and royalties to the supply price if they are known, or to envisage a situation where governments may be willing to have their share of the oil revenue reduced in order to make a given oil production more economically attractive. To simplify the analysis, we have measured the supply prices net of taxes and royalties.

⁴Taking the simple mean of all available estimates to represent the base case can be justified on the basis of giving an equal weight to all sources (except in the case of old data). Any other way of selecting the base case would entail assigning a specific importance to each estimate presumably in accordance with the source which for practical purposes is not viewed as superior to the presently used method.

⁵R. Uhler, Oil and Gas Finding Costs; and The Globe and Mail, Oct. 1979. For other estimates of finding costs see The Globe and Mail, Jan. 30, 1980; and Oilweek, Feb. 12, 1979, p. 68. The finding cost for one single year, however, is a difficult concept since reserves discovered in one year may be a result of current expenditures as well as expenditures incurred in the past.

⁶Since two supply estimates (NEB and ERCB) included in this chapter are at least two years old, it is possible that the figures in Table 4.1 are conservative.

⁷For a more detailed breakdown between provinces, see for example the estimates for the period of 1973-1977 in current dollars published in Oilweek, Feb. 12, 1979, pp. 67-68, and Feb. 11, 1980, pp. 48-53. For the purpose of this paper, the Oilweek estimates have been translated into 1980 dollars and are the averages of the three western Canada producing provinces. Other estimates were made available by industry sources or can be found in Canada, National Energy Board, Canadian Oil Supply and Requirements (Ottawa, National Energy Board, 1978), p. 41.

⁸See The Globe and Mail, Sept. 26, 1978, for estimates by Dome Petroleum.

⁹These figures have been calculated from Oilweek, Feb. 12, 1979, p. 60; and Canadian Petroleum Association, Statistical Handbook (Calgary: Canadian Petroleum Association, 1979).

¹⁰The selling price of oil on the world market varies a great deal between exporting countries. The lower price shown here is charged by Saudi Arabia, which exports some 147,400 bbl/day to Canada, while the upper price is charged by Algeria, exporting to Canada some 13,400 bbl/day. For the purpose of calculating the cost of imported oil landed at Montreal, a blended 'world price' is computed according to each country's price and amount of oil it sells to Canada. This price is currently some \$35/bbl (see The Globe and Mail, April 2, 1980). Canada presently imports about 500,000 barrels of oil per day.

¹¹For a basic estimate of the cost of synthetic crude oil, see Canada, Department of Energy, Mines and Resources, Oil Sands and Heavy Oils: The Prospects (Ottawa: Supply and Services, 1977), pp. 16-17 and 31-32.

¹²Canada, NEB, Canadian Oil, 1978, pp. 57-62.

¹³Since synthetic crude oil is in fact an upgraded bitumen, as a refinery feedstock it commands a premium of some \$1/bbl relative to conventional light or medium crude.

¹⁴See Canada, Department of Energy, Mines and Resources, The National Energy Program (Ottawa: Minister of Supply and Services, 1980), p. 30.

¹⁵One feature of the proposed National Energy Program is to blend the total cost of oil imports into the price that all oil consumers pay (the blended price). This is to be done through an extension of the existing system of refinery levies. A new Petroleum Compensation Charge (PCC) will be phased in, incorporating the Syncrude Levy, to cover the costs of oil import compensation. By the end of 1980, the PCC stood at \$2.55 per barrel (\$1.75 Syncrude Levy and \$0.80 oil import compensation costs), and it is scheduled to be increased by \$2.50 per barrel on January 1 of 1981, 1982 and 1983. See *ibid*, p. 30.

¹⁶The first proposal to build a 30,000 bbl/d heavy oil upgrading plant was put forward by Husky Oil in 1975 (see Oilweek, Oct. 11, 1976). The proposal was later changed to a plant capacity of 100,000 bbl/d (The Globe and Mail, Sept. 16, 1978). Other proposals included Pacific Petroleum's 100,000 bbl/d plant (1978); Petrosar's 100,000 bbl/d plant (1978); and Husky's 50,000 bbl/d plant (1979).

¹⁷Canada, NEB, Canadian Oil, p. 41. See also Canada, EMR, Oil Sands and Heavy Oils, p. 29, where it is suggested that an optimal size of an upgrading plant is in the order of 100,000 bbl/d but a plant half that size might be economic.

¹⁸See for example the cost estimates in Canada, NEB, Canadian Oil, p. 41; or Canada, EMR, Oil Sands and Heavy Oils, pp. 29-30.

¹⁹For the most recent and comprehensive review of these processes, containing a set of cost estimates, see D. B. Black and S. G. Dunn, "An Overview of Commercially Proven Technology for Upgrading Heavy Oils" (Calgary: Associated Pullman-Kellogg Ltd., September 1979). The cost estimates contained in this publication are said to have ± 30 percent accuracy.

²⁰Much like synthetic crude oil, upgraded heavy oil would be of a higher quality than conventional crude and therefore a more desirable refinery feedstock which could command a premium of up to \$1/bbl over conventional oil. This would still seem insufficient, however, to change the conclusion of the economic viability of upgraded heavy oil production.

²¹See estimates by Husky Oil relevant to the Lloydminster-type heavy oil in Canada, NEB, Canadian Oil, p. 38.

²²See the discussion in J. Philip Prince, Enhanced Oil Recovery Potential in Canada, (Calgary: Canadian Energy Research Institute, March 1980), Study No. 9, Chapter 3, pp. 25-26.

²³Prince, Enhanced Oil Recovery.

²⁴Ibid, p.26.

²⁵Based on Prince, Enhanced Oil Recovery; and industry sources.

²⁶The low and high extremes of this price have been obtained by adding \$5.60 to the extreme estimates of the heavy oil lifting costs of \$5.57 and \$11.66.

Chapter 5

LIQUID FUEL ALTERNATIVES

Z. Charles Slagorsky

Introduction

The idea of alternative liquid fuels has been attracting increasing attention as a result of changes in economic and political circumstances during the 1970s. The rising price of oil has naturally led consumers to look for alternative fuels. Moreover, the supply of the new fuels is viewed as being more secure in the light of possible oil embargoes, as long as it is manufactured from domestically available resources.

The alternative liquid fuels most frequently discussed today include various alcohol fuels and liquids derived from coal. Considered here will be the use of methanol, ethanol, and liquefied coal.

Methanol and ethanol are the two most promising alternative fuels based on alcohol derived through the fermentation of biomass. Methanol (CH_3OH) is a toxic and explosive liquid derived from several possible sources including coal, municipal solid waste, forest products, agricultural products, peat and natural gas, all of which are available in Canada. As a fuel (methyl alcohol) methanol is used together with small percentages of higher alcohols. The crude oil-derived fuels, which methanol could displace, are primarily fuel oils used for residential heating and gasoline in transport. In home heating, methanol has the potential of being a more efficient furnace fuel but, since it is toxic, a safe storage system would have to be designed before it could be used on a wide scale. In transport, methanol could be used as a blend with gasoline in cars or as a straight methanol fuel. When blended with gasoline, methanol would be expected to yield the same amount of energy during combustion as the displaced gasoline.¹ There is, however, a limit of about 10 percent on the amount of methanol which can be used in a blend with gasoline since at higher levels of alcohol content in gasoline, the water component of the solution separates and collects in storage tanks. This puts a limit on the amount of gasoline which could be displaced by

methanol in the transport sector. The use of straight methanol would increase energy efficiency relative to a gasoline engine but the economy-wide fuel distribution system would have to be altered to accommodate the 45 percent increase in volume required for an equal vehicle output.² Since vehicle power systems based on a methanol-gasoline blend would not be those using straight methanol, changes to the distribution system would need to be far-reaching if both approaches were developed. All existing vehicles, as well as home heating furnaces, would have to be retrofitted to be compatible with the new fuels.

At present, about 1200 tonnes of methanol per day are produced in Canada, but current markets are for chemical methanol, not methyl fuel. The future contribution of methyl fuel in this country is therefore dependent on the success of its timely penetration of selected markets. The technology of methanol production is well developed, but currently the problem is in its limited usage rather than limited supply.

Ethanol (C_2H_5OH) appears economically less attractive than methanol although its calorific value is greater. On a weight basis, ethanol has an energy value of about 12,000 Btu per pound compared with some 8,600 for methanol. Since the hydrocarbon portion of the ethanol molecule is larger in relation to the alcohol (hydroxyl) portion, ethanol also exhibits better compatibility with a hydrocarbon fuel such as gasoline. Hence, it could also be used as a blend with gasoline in transport as a cleaner-burning and more energy-efficient fuel than methanol. As the cost estimates below suggest, however, the production of ethanol is economically inferior to that of methanol.

Owing to the vast reserves of coal in Canada, coal liquefaction is more frequently being viewed as a promising source of alternative liquid fuels. The technology of liquefying coal is well known³ and has been utilized in various parts of the world since the early-1900s. Coal is basically a hydrocarbon deficient in hydrogen and thus the liquefaction process consists of either adding hydrogen or rejecting excess carbon. As a result, a product is obtained which has a higher hydrogen-to-carbon ratio and a lower average molecular weight than the parent coal. The liquefaction process results in a wide range of products suitable for further refining to obtain gasoline, boiler fuel and heating oil. Refining of coal liquids on a large scale, however, would require new refineries or substantial adjustments to existing ones; initially, however, small quantities of coal liquids

could be blended with conventional crude oil as refinery feedstock without difficulties.

Estimates of Cost

Although a great deal is known about these alternative liquid fuels and we are technically capable of producing them, the key to their increased production and utilization is cost. Not only the cost of production itself but also the associated costs of switching from the use of one fuel to another must be considered. Generally speaking, though, as the cost of imported crude oil rises,⁴ the relative prices of various fuels change, making previously uneconomic fuels profitable to produce. The contribution of these new fuels in Canada will thus depend on the cost at which they can be produced from indigenous resources and the success in penetrating markets in which the cost of switching from the use of conventional liquid fuels is the lowest.

Available estimates of the cost of producing alternative liquid fuels must be viewed as uncertain at best since, with the exception of methanol, they are not yet being produced on a commercial scale in Canada. At the same time, their relative costs will be crucial in deciding which of the new fuels should be given most emphasis.

It has been estimated that methyl fuel produced in Canada would cost somewhere between \$23 and \$52 per barrel of oil displaced,⁵ depending on the type of feedstock used and the location of the plant. This means that once the price of imported oil reaches this level, it will become comparable to the cost of producing methanol. It does not mean, however, that methanol as a fuel would then become cost-competitive with fuels derived from crude oil in household and industrial applications. Since a methanol distribution system is not in place, and motor vehicles and home furnaces would require modifications, all of which would be costly, a discount relative to the price of conventional fuels would be required for methanol before the two types of fuels are substituted.

It appears that the least costly feedstock for methanol production may be coal in Saskatchewan, Alberta and B.C. or lignite and peat in Ontario. It seems cheaper to produce methanol near the resource (coal) and transport it to markets in Ontario or Quebec than to produce it in the consuming provinces from coal shipped there from western Canada.⁶ A gallon of methyl fuel produced from coal could cost some 55 cents if produced in western Canada. In Ontario, with peat used as the source, the cost would be slightly higher. Produced

from wood wastes and natural gas in B.C., Ontario or Quebec, the price per gallon would probably rise to about 75 cents. In comparison, if natural gas were used as feedstock (priced at the export price of \$US 4.47/Mcf), methanol produced in Alberta would cost around 80 cents per gallon. If such a producing plant were located in Ontario, the cost would rise to about 87 cents. Although these are rough cost estimates, they provide some basis for comparison with the cost of crude oil-derived fuels. Compared with a mid-1980 price of imported crude oil of \$38 per barrel on average, the cost of producing many of the new fuels falls within an estimated range of \$23 to \$52 per barrel. Because of the substantial supply potential, Canada stands a good chance to become a leader among the industrial countries in developing the production technology and use of alternative fuels. It may, however, take some time before we see a much wider use of methyl fuel. In transportation, auto makers would have to undertake engine modifications estimated at about \$500 per vehicle in order to make new cars compatible with methanol. Retrofitting existing engines for the use of methanol is not considered economic and the problem of cold temperature starting remains to be solved if methanol is to be used in Canada on a year-round basis.

It has been mentioned that ethanol is a superior fuel to methanol but that it is more expensive to produce. When blended (10 percent) with regular gasoline, ethanol increases the octane rating of the 'gasohol' blend making it an excellent fuel for summer driving with no engine modifications necessary. Well over 1,000 service stations in the U.S. now market gasohol (produced there with a subsidy) and report that consumers accept the new fuel; it averages about 20 percent of the sale volume of those outlets which offer it.⁷ A further advantage of ethanol is that the capital cost of a plant producing 5.5 million gallons of ethyl alcohol (ethanol) per year is estimated to be between \$12 and \$15 million whereas a comparable facility producing methanol may cost from \$100 to \$150 million.⁸

The biggest problem in ethanol production, however, is the cost of feedstock. Agricultural products (wheat, corn, sugar cane) are very well suited but too expensive relative to their alternative use as food or livestock feed. Similarly, the use of forest products (e.g., poplar tree plantations) as feedstock is expensive, involves an alternative use of arable land and may cause environmental problems. If grain were used as the main source to produce ethanol, depending on the speed of the gasohol programme, within several years the prices of grain could be driven up and translated into high values of agricultural land. High land prices could in turn cause a general rise of

food and livestock prices. It has been estimated that ethanol to displace crude oil-derived gasoline would cost some \$50 per barrel of oil if residual wood products or municipal waste were used as the feedstock. Production of ethanol from agricultural crops could prove to be more than twice as expensive. From an environmental point of view, gasohol use in automobiles would reduce the emission of carbon monoxide, but emission of smog-causing petrochemical ingredients would generally increase: nitrogen oxides by 6.5 percent and evaporative hydrocarbons by 62 percent.⁹

Among the alternative liquid fuels discussed here, the economics of coal liquefaction is probably the most promising. Since the technology is well established, coal liquefaction plants could readily be built either in the eastern consuming provinces or in western Canada. It has been estimated that it would be possible to produce a barrel of synthetic oil from coal for between \$25 and \$35.¹⁰ A coal liquefaction plant capable of producing 120,000 barrels of oil per day would cost some \$5 billion, take about four years to construct, and require a feed of 23 million tons of coal a year (Canada currently produces 30 million tons per year).¹¹ Not unlike oil sands plants, a coal liquefaction operation could become economical if the prevailing world price could be realized.¹²

Because of the vast estimated economically recoverable reserves of coal in western Canada alone (20 billion tons), many arguments have been put forward in favour of an early coal liquefaction development. Yet, an oil sands plant appears more economical. Though the construction cost of, for example, the Alsands oil sands project has been estimated at about \$6.7 billion, estimates of operating cost for Alsands are less than half the \$800 million per year projected for a coal liquefaction plant.¹³ One advantage of the latter, however, is that it would use less water than an oil sands plant. Arguments have also been advanced that it would cause less environmental damage.¹⁴ Others have claimed that synfuels (synthetic fuels obtained through, for instance, coal liquefaction or gasification) would contribute proportionately more than other fossil fuels to increasing concentrations of carbon dioxide in the earth's atmosphere and in addition leave dangerous carcinogenic, mutagenic and other toxic compounds for disposal after production.¹⁵

Demand and Supply

Given preliminary production cost estimates for the alternative liquid fuels, what are the prospects for their demand and supply in the years ahead?

In the case of methanol, only negligible amounts are currently used for fuel purposes. As an alternative fuel methanol stands the best chance of adoption in isolated or contained situations, where its incompatibility with the oil products storage and distribution system is of no concern, or where it can readily be accommodated. The production and marketing of methanol is particularly attractive for those regions in Canada where no crude oil reserves exist: Ontario, Quebec and the Atlantic provinces.¹⁶ Natural gas (Nova Scotia), coal (Nova Scotia, New Brunswick), peat and lignite (Ontario), and municipal solid waste (Ontario, Quebec) could be used as indigenously available feedstocks in methanol production. Methanol produced in this manner could displace gasoline used in vehicle fleets and other fuels in stationary uses. Moreover, if a technique presently being tested of blending methanol with diesel fuel proves successful, methyl fuel could also displace some diesel oil in truck fleets. If the problem of safely storing methanol for the purpose of space heating were resolved, a large further demand potential would unfold within the household and the commercial sectors.

Because the use of a blend of ethanol (10 percent) and unleaded gasoline (90 percent) in automobiles requires no vehicle adjustment, Canadian motorists will be consuming ethanol before methanol. Mohawk Oil Company Ltd. has recently announced a plan to produce some 1.75 million gallons of ethanol per year in a converted distillery at Minnedosa, Manitoba, with anticipated expansion expected to increase the capacity to the range of 4 to 5 million gallons per year.¹⁷ Possibly up to 100 million gallons of ethanol per year could be produced in Canada by 1990, displacing some 8,000 barrels per day of crude oil (102 million gallons per year). Although ethanol could displace roughly the same amount of gasoline, and thus free a similar volume of crude oil for other uses, it is currently more expensive to produce than the gasoline it would displace. The Mohawk Oil venture has been made possible by an Act of the Manitoba government which exempted gasohol produced from Canadian-made alcohol from all provincial gasoline taxes. The company is expecting to begin marketing gasohol in Manitoba by the fall of 1980. Depending on the octane number of the base gasoline, a gallon of ethanol can displace between 0.7 and 1.0 gallons of gasoline. The upper limit of ethanol's

contribution as an alternative transportation fuel is therefore fixed between 7 and 10 percent of gasoline consumption. This is not a large contribution, but it is one which could be readily made (especially in summer driving) once the ethanol has been produced. Hence, although expensive, ethanol could nevertheless have a considerable political and regional appeal.

It has been mentioned that the refining of large quantities of coal liquids would necessitate new refineries or substantial adjustments to existing ones. Concerted effort would, therefore, be required if coal liquefaction were to be adopted on a large scale as a means of providing alternative fuels to crude oil. It does not appear likely that more than 50,000 barrels of synthetic crude per day will be produced from coal by the end of this decade. Thus far only one company, Algas Resources Limited of Calgary, is seriously considering building a coal liquefaction plant in Alberta in the late-1980s or early-1990s.¹⁸ This demonstration plant would be producing 20,000 barrels per day. A larger plant, producing some 120,000 barrels per day has been predicted to be in operation by the mid or late-1990s.¹⁹ Coal liquefaction (and gasification) can be viewed with optimism over the long term given the vast reserves of coal in Canada. It is a particularly attractive option for some of the oil-poor regions such as Ontario (with lignite reserves) and the Atlantic provinces (with coal reserves especially in Nova Scotia and New Brunswick).

Concluding Comment

The future supply, demand and cost estimates of the new fuels are, of course, only tentative. They will only materialize within a suitable institutional framework wherein investors find it possible and attractive to invest in the development and production of the alternative fuels and consumers are encouraged to switch from the use of one fuel to another. It is worth noting that it is in the market place that development and marketing problems vis-à-vis the new fuels would have to be solved in an efficient manner. Once the market signals are 'right', owners of resources, fuel refiners, and vehicle and home furnace manufacturers may be expected to undertake the necessary research and development required to minimize the technical risk of production. Once new products designed to run on the new fuels are developed at competitive prices, consumers, too, may be expected to make the switch.

When one compares the current price of crude oil in Canada (\$17.75 per barrel) with the cost estimates of producing alternative fuels presented in this brief analysis, it is apparent that the most serious obstacle for the new fuels is the fact that they are presently unable to compete with the low-priced crude oil products. Other barriers, including industrial inertia, inefficient regulatory procedures and consumer attitudes, could stand in the way of rapid development of alternative liquid fuels. It is clear, however, that unless the Canadian price of crude oil rises, very little progress can be expected. Given our endowment of natural gas and forest resources, both used to produce biomass-based fuels, and our coal resources, this country has a unique opportunity among the industrial nations to quickly develop the technology in order to have access to alternative liquid fuels.

Footnotes

¹Ontario, Liquid Fuels in Ontario's Future: Findings and Recommendations, Report of the Advisory Group on Synthetic Liquid Fuels of the Ministry of Energy, (Toronto: Ontario Ministry of Energy, 1978), vol. 1, p. 3-16.

²Liquid Fuels in Ontario's Future, p. 3-17.

³For a review of the four main methods for coal liquefaction, see P. W. Gregory; W. Kasis; and J. M. Rassbeck, "Is Coal Liquefaction a Viable Synfuel Operation in Alberta?" Paper presented at Technical Meeting of Petroleum Society of CIM, Calgary, May 25-28, 1980.

⁴In nominal terms, the price of imported oil rose by about 340 percent between 1973 and 1974, and from late 1978 to mid-1980 the average price advanced by some 140 percent. In real terms, the former change translates to 250 percent and the latter to 85 percent. See the editorial in The Globe and Mail, June 11, 1980.

⁵Available sources include, Canada, Department of Energy, Mines and Resources, "Discussion Paper on Liquid Fuel Options" (Ottawa: Minister of Supply and Services, 1980); Ontario, Economic Analysis of Synthetic Liquid Fuels, Report of the Advisory Group on Synthetic Liquid Fuels of the Ministry of Energy, (Toronto: Ontario Ministry of Energy, 1978), vol. 2, prepared by Canadian Resourcecon Ltd.; Inter-Group Consulting Economists Ltd., Liquid Fuels From Renewable Resources, prepared for the Government of Canada Interdepartmental Steering Committee on Canadian Renewable Liquid Fuels Program Options (Winnipeg: Inter-Group Consulting Economists Ltd., May 1978); or J. E. Feick, and D. J. McConaghy, "The Relative Economics of Recovering and Upgrading Alberta's Hydrocarbon Resources," The Journal of Canadian Petroleum Technology, April-June 1976, pp. 19-26.

⁶Liquid Fuels in Ontario's Future, p. 3-25.

⁷Oil and Gas Journal, March 3, 1980, pp. 19-24.

⁸Estimates by Stone and Webster Canada Ltd., who are designing the first commercial plant in North America in Liberal, Kansas, where grain from wheat will be the feedstock. See Oilweek, October 15, 1979, pp. 36-39.

⁹Oil and Gas Journal, June 2, 1980, editorial.

¹⁰N. Berkowitz, a professor of engineering at the University of Alberta and vice-chairman of the Alberta Energy Resources Conservation Board, estimated the price to be between \$25 and \$30 per barrel; while a study by the Canada West Foundation estimated the price at \$35 per barrel for a plant in Western Canada. See The Calgary Herald, June 20, 1980, and The Globe and Mail, June 20, 1980.

¹¹The Globe and Mail, June 20, 1980.

¹²It must be kept in mind, however, that embarking on a large-scale development of a coal liquefaction plant would necessitate substantial modifications to existing refineries to make them compatible with the new feedstock. Liquefied coal would therefore have to be available to refineries at a discount to help finance the retrofitting expenditures.

¹³The Calgary Herald, May 27, 1980.

¹⁴See, for instance, the statement by Algas Resources Ltd. of Calgary which is proposing the first coal liquefaction plant in Alberta to be completed by the end of this decade. The Calgary Herald, May 27, 1980.

¹⁵See the reference to the U.S. Department of Energy assessment in Oil and Gas Journal, March 10, 1980, p. 51.

¹⁶Although oil has been discovered off the coast of Newfoundland, the commencement of production is uncertain. See Chapter 4.

¹⁷Oilweek, June 16, 1980, pp. 8-9.

¹⁸The Calgary Herald, May 27, 1980.

¹⁹N. Berkowitz, of the Alberta Energy Resources Conservation Board and the University of Alberta, in The Globe and Mail, June 20, 1980.

PART III
PRICES, COSTS AND INCENTIVES

Chapter 6

THE PRICING OF CANADIAN OIL: INSUFFICIENT INFORMATION ON COSTS

Z. Charles Slagorsky

Introduction

The purpose of this chapter is to put the findings of the two preceding chapters into perspective within the framework of economic decision-making in this country. It was found in Chapter 4 that except for the primary recovery of conventional oil, all other sources of oil in Canada are uneconomic at the low domestic price of oil. In Chapter 5 it was shown that alternative liquid fuels exist that could be produced at a cost comparable to crude oil-based fuels. However, because of required changes in the liquid fuel industry, distribution network and product design, all of which would imply additional cost, the Canadian price of oil is still too low for the production of the new fuels to become economically viable. In light of these findings it is clear that, if oil self-sufficiency is to be achieved, the Canadian price of crude oil must rise. The problem is to ascertain by how much the Canadian price would have to rise: would it have to rise to the level of the world price or to somewhere (and where) between the Canadian and the world price? It is a formidable problem to estimate the supply price or prices necessary to achieve oil self-sufficiency.

The supply price of a commodity is the price at which a producer will be willing to produce it; it covers all costs incurred during production plus a rate of return on investment. The concept thus embraces the producer's expectations of both future prices and costs.¹ In order to calculate the supply price of oil, therefore, the cost of oil production must be known or estimated. The problem is not that cost information does not exist, but rather that it is not publicly available. The reader has been cautioned in Chapters 4 and 5 that the results of the analysis there were conditional upon the reliability of the cost information used.

The critical point about the cost information is that it is not needed primarily for the purpose of solving the problem of pricing of petroleum in Canada, since ultimately the (opportunity) cost of

Canadian oil is determined by the world price, but is required in order to ascertain the return on the oil producers' investment as the Canadian price moves towards the world level. The situation is further complicated by the existence of various allowances and other measures open to the producers which supplement the selling price. For these reasons the economic and political implications of the issue of information on costs are significant.

The 'Made in Canada' Price of Oil

Arguments have been advanced both for and against the move of the Canadian price to the world level.² One area of disagreement centres on the distribution of the additional revenue which a higher price would generate. If we were to raise the domestic price closer to a world level, should some or all of the additional revenue go to the producers, or should some or all of the extra revenue be absorbed by the two levels of government? Nobody seems to argue that all of the extra revenue should go either to the producers or the governments, but that nonetheless leaves the question of revenue distribution unresolved. The oil producers argue for higher returns on their investment which would enable them to increase production of more expensive oil (e.g., oil sands, enhanced recovery, etc.) on the way to self-sufficiency. The federal government, on the other hand, is attempting to keep the oil industry's returns in line with other sectors of the economy as the price of oil goes up and at the same time to increase its own revenues.

The proposed federal National Energy Program has suggested an increase in the price of oil which would bring the domestic price in line with the cost of producing new Canadian oil from oil sands and other higher-cost sources and with the cost of imported oil.³ This has been referred to as 'replacement cost' pricing or pricing according to the marginal or incremental cost of production of domestic oil. In the words of the Minister, the new price would be 'made in Canada' and it would be a 'blended price'. Producers would receive a given rate of return on their investment in excess of all costs incurred during production. Under this proposal, more than one price would be in effect at any one time according to the various types of oil being produced.

The replacement cost concept is not new. First thoroughly treated by Lovejoy and Homan in 1963, the conventional idea of replacement cost per barrel of crude oil can be summarized in the following way:⁴

It can be defined by,

- i) current costs of production (lifting cost) divided by output; plus
- ii) current development costs divided by the proven reserves added by development activity ('extensions' and 'revisions'); plus
- iii) current finding costs divided by the proven reserves added by exploratory activity ('discoveries'); and these are then
- iv) adjusted for costs allocated to natural gas and natural gas liquids.

All costs and quantities relate to the same time period, for instance one year. Lovejoy and Homan observe that the above costs incurred in any one year do not represent the sum of costs assignable to the oil produced during the same time. Only lifting costs meet such a criterion. The logic of 'adding three different barrels of oil' can be seen in the fact that an oil producer, in order to replace a barrel of oil, must find another barrel, develop it, and lift it to the surface, all at today's costs, which in turn necessitates the use of the three different costs.⁵ Thus the replacement cost cannot be considered as an accurate measure of current costs, but rather should be viewed as a cost standard that can be compared with the prevailing price of oil. The national averages of these cost figures could, therefore, be very useful for trend comparisons over periods of time, and

... generally speaking, the statistics on finding cost should be the most critically important indicator of future cost prospects for exploration programs. Any pronounced trend increase in this figure should, if properly defined, be recognized as tantamount to 'handwriting on the wall' and must be given sober acknowledgement in planning drilling programs at the level of the individual oil company, and in making recommendations for the appropriate scheduling of over-all fuel-use patterns at the national level.⁶

In spite of the potential usefulness of the replacement cost concept, its limitations are apparent. As shown in Chapters 4 and 5, and pointed out above, the available cost information--critical in estimating the replacement cost--is sparse and unreliable, and it could potentially give rise to far-reaching changes in the allocation of resources within the economy. A further limitation is presented by the use of reserve estimates in the cost calculation. The problem is in

the definition of reserves which is essentially arbitrary. The American Petroleum Institute, for instance, defines 'recoverable reserves' of crude oil under existing technology and economic conditions, which means that the ultimate reserves of any given reservoir can change due to new technology or changed price levels.⁷ Another obvious difficulty is introduced by the time lag between the actual outlays on exploration and development, and the time of production.

Lovejoy and Homan also call attention to the fact that the replacement cost concept thus defined has nothing in common with the concept of historical economic cost (and therefore economic profit) or with the conventional accounting costs and profit.⁸ In order to calculate historical cost, all current and past expenditures, capital and operating, must be isolated and properly assigned to present production. Thus portions of past finding and development outlays would have to be charged to present production which

. . . appears impracticable for any company to fragment its past costs in such a way that the various bits and pieces of past capital outlay and opportunity cost would be allocated to the production of a particular year.⁹

Lovejoy and Homan consider it necessary, therefore, that the rigorous concept of historical economic cost be abandoned in favour of an alternative method of analysis which may give a ". . . rough estimation of costs." They conclude that a modified and improved replacement cost concept, with some way of lagging the finding and development costs according to an estimated average interval between expenditure and production, may offer the best alternative.¹⁰ It is clear, however, that the usefulness of the replacement cost concept rests heavily on the availability of accurate cost information.

If costs were reasonably well known, then the concept of replacement cost could be considered efficient and equitable since a barrel of oil would be sold at a price covering all costs of producing another barrel, ensuring in the process (since the costs would be known) that the least costly oil is produced first. A further, more critical, assumption would have to be made, however, if an efficient resource allocation was to be achieved by the replacement cost pricing mechanism. It would have to be assumed that the ranking of the costs of other alternative fuels were known since only then could an efficient (i.e., least-cost) allocation of resources among alternative fuels take place. It should be clear that the stumbling block in this approach to pricing is that no definitive information exists as to what

the replacement cost is or what the costs of the alternatives are.¹¹ Also, the definition of an 'adequate return' on producers' investment is not a simple matter, given the variations in risks and the alternatives available to investors.

Chapter 4 presented some estimates of the cost of producing oil in Canada but they all had a strong element of uncertainty associated with them. It was made clear, for example, that we have a better understanding of the cost of oil from the oil sands than from the frontier offshore areas where no previous experience exists and the extent of the reserves are not yet defined and hence the costs are unknown. While the knowledge of the cost of enhanced recovery and heavy oil operations is presently expanding, the greatest experience lies in the production of conventional oil. A frequent problem with the latter, however, is that costs vary between reservoirs and are not in any case made publicly available. It is not that the cost information does not exist; it is simply that a lot of the information is not in the public domain where it would have to be if replacement cost pricing were to be adopted. Furthermore, even private information is often incomplete and such cost information is frequently of a proprietary nature. Keeping one's cost of production down is rewarded by profits, and profits in turn are the main motivating force in the marketplace. It is, therefore, not the case that cost information is revealed; revealing it and receiving a given rate of return above cost would change the whole nature of the oil business from a private enterprise to a public utility type of operation.

Thus, a move to replacement cost pricing is, in effect, a move towards a regulated utility approach for the oil and gas industry. Such a pricing mechanism would include in the replacement cost of a barrel of oil an administered rate of return on capital much like the present situation for electricity pricing, the pricing of telephone service, and other public utilities referred to as natural monopolies. From the point of view of society as a whole, natural monopolies offer an advantage relative to other market structures. One firm, the natural monopoly, is usually granted an exclusive franchise with the result that the unit cost of output is much lower than would be the case if several producers tried to supply the same service to the same customers. Lower price and greater availability of the product are thus offered by one producer serving the entire market, rather than by a group of smaller producers each operating at a higher cost and each competing for a portion of the market. Instead of charging what the market will bear, as a monopolist would, natural monopolies are then permitted (by government regulatory boards) to charge only the average

cost of production plus a specified rate of return.¹² The important characteristic of a natural monopoly, therefore, is that it increases efficiency in situations where the economies of scale can be captured by a single firm allowed to dominate the market but controlled in its pricing policies.

It is clear, however, that the production of oil does not represent conditions for natural monopoly. On the other hand, it should be recognized that the 'blended price' or the 'made in Canada price', both of which are variations of the replacement cost pricing proposal, have been suggested by the federal government in order to exercise a greater control over the returns of the oil industry as the price of oil increases. If the Canadian price (currently less than half the world price) was to rise to the world level, the industry would clearly stand to receive a marked increase in revenues. This is the central issue. Increases in the oil industry's revenues will be needed if the production of more expensive indigenous oil is to be stepped up but, as was suggested in Chapter 4, less than the world price might prove to be sufficient. In the absence of OPEC, the case for controlling the industry's profits would be more difficult to make since then the price increases would be reflecting the rising cost of producing oil from increasingly more expensive sources along with the cost of alternative fuels. Since increases in the Canadian price of oil are also needed for another reason--curtailment of demand, or the growth of demand--the federal government's concern about the oil industry's returns is understandable. Large and undesirable shifts in resource allocation within the economy could result from increased returns based on OPEC administered prices.

Yet, in the long run, when all cheaper oil resources will have been depleted, the Canadian price will inevitably have to move towards the world price whatever the latter may then be. In the meantime, unlike other western industrial countries, Canada has the luxury of moving in stages in the direction of the world price rather than simply accepting it and absorbing in the process all the economic consequences. Japan, West Germany, and other industrial countries have had no choice but to pay the world price and they still manage to have the world's most competitive industries. This raises the question of whether it is more beneficial for an economy to be sheltered from the effects of higher prices of one industrial input (energy), giving the country's products a short-term competitive edge on the international market; or whether the price shelter will send 'wrong' signals through the economy with planning and new investment being carried out much like in the past, resulting in less energy efficient transportation,

home heating and factory installations, and, of course, in obvious negative effects on the country's long-term international competitive position. An oil price shelter will also have a negative effect on the objective of becoming self-sufficient in oil because the economic incentive to reach it will be removed unless non-price incentives and government activities are greatly extended. Countries like Japan and West Germany have shown that it is possible to cope with world prices of oil through the regular market channels. The difference between them and Canada is that this country is also a significant producer of oil and that the UPEC price is too high relative to the Canadian price, leaving the troublesome problem of oil revenue distribution.

The Problem of Revenue Distribution

If the present distribution of revenue from the sale of a barrel of oil remains unchanged and the price of oil increases for reasons other than cost, then indeed every one of the three recipients will realize an 'excess' revenue relative to what it was before.¹³ The netback to producers will increase, providing funds for a greater reinvestment and greater output of more expensive oil, and governments will end up with greater general revenues which can be used for various purposes.

It appears that given the positions of both oil producers and the two levels of government in Canada it is easier to subject to scrutiny and regulation the spending of the oil producers than spending of governments. When the oil industry receives larger revenues (profits), they can be either paid out as dividends to shareholders, used to acquire other businesses or reinvested. It should be noted that all of these three possibilities imply an observable process over which one or both levels of government can exercise some influence: through changes in regulations governing business takeovers, through changes in tax rules as they apply to shareholders or corporations, by attending incentives which affect the level of investment, or by specific grants on the part of government. Contrasting this arrangement is the fact that much of government spending on continuing programs usually proceeds without any vigorous evaluation of their past performance and that, therefore, the only check on spending of governments is provided during elections. But time during an election campaign is limited and other issues may take precedence. When it is recognized that election choices are based heavily on these prominent issues, it can hardly be asserted that a very efficient check exists on the ways governments might spend increased oil revenues. Although this may not be a critical issue in the pricing debate per se, it would seem desirable to

have a systematic method of looking back at the ways oil revenues were spent in both the private and the public sectors since, clearly, the additional revenue from increased domestic oil prices will be large. Thus the revenue distribution is indeed a serious problem that must be resolved before embarking on any longer-term energy policy. Added to the industry-government distribution problem are the additional dimensions of the positions of oil consumers, and the distribution of revenue between the two governments which are very much of a political nature.

Assuming that high world oil prices are here to stay, a staged progress of the domestic price to higher levels is inevitable and should be initiated without much delay.¹⁴ In the long run we might be better off by making the price changes more quickly, much like our major international trading partners, for it seldom pays to insulate consumers from permanent price change.¹⁵ A prolonged period of an artificial price shelter (in effect in Canada and the U.S. since 1974 in the case of crude oil) will only introduce additional market distortions whose consequences may be even less desirable than those of the original problem.¹⁶

In spite of the fact that the case for natural monopoly pricing cannot be made for the oil and gas industry, an attempt by either of the levels of government to tax what may be perceived as 'excess' profits would imply a similar type of regulation with some 'allowed' profit over cost.¹⁷ To determine an 'excess' profit would likely mean that the amount of cost reporting would have to increase relative to what it is now and that it would have to be made more comprehensive in order that problems do not arise due to different definitions of basic cost concepts (e.g., finding cost, developing cost, lifting cost).¹⁸ Since it is argued below that, for a different reason, the availability of cost information is essential, it may be useful also to ask whether something could be gained by improving on current practices, considering that much of the information is available for internal use in any event. A better public understanding of the unit cost of oil production would result and it could lessen the tension that has developed between the oil and gas industry and the federal government.¹⁹

Why is Cost Information Essential?

The one clear reason behind the need to have the oil industry's cost information available is for the improvement in the application of policy to energy matters. Although regulated, the Canadian economy is

a mixture of private and public sectors. The overall policy goals are set by the government and then, to a large extent through incentives, tax policies, etc., pursued by the private sector. This is the reality. In order to decide on large energy developments requiring considerable investments such as the oil sands, off-shore oil, heavy oil or enhanced recovery, it is essential that the federal government has a good understanding of the respective costs so that an effective policy (including incentives such as frontier depletion allowances, various grants, write-offs, etc.) can be implemented. The public also has the right to have access to such cost information. Ideally, for the purpose of implementing an effective fiscal policy, the government should have reliable estimates not only of the cost of producing oil from various sources but also of the costs of alternative fuels. Only then could an efficient long-run allocation of resources be achieved. It must be ensured, for instance, that in pursuing the objective of oil self-sufficiency we do not leap over potentially cheaper sources to oil which could be more expensive, or that the development of alternative fuels is not delayed due to a lack of cost information. Since achieving self-sufficiency will require a vast amount of investment during the 1980s, inadequate cost information could prove damaging to the Canadian economy.

Footnotes

¹See also footnote 3 in Chapter 4.

²Examples of such arguments can be found, for instance, in Toronto Dominion Bank, Canadian Oil and Natural Gas: Toward an Appropriate Price Adjustment (Toronto: Toronto Dominion Bank, August 1980), Occasional Paper, which presented the arguments for an increase; or in J. Philip Prince, Enhanced Oil Recovery Potential in Canada (Calgary: Canadian Energy Research Institute, March 1980), Study No. 9, which reviews the arguments on both sides.

³See Canada, Department of Energy, Mines and Resources, The National Energy Program (Ottawa: Supply and Services, 1980), pp. 23-32; or see, for instance, "Energy Pricing and National Unity," an address by the Hon. M. Lalonde to the 7th Annual Financial Conference, Toronto, May 6, 1980.

⁴Adapted from W. F. Lovejoy, and P. T. Homan, Problems of Cost Analysis in the Petroleum Industry (Dallas: Southern Methodist University Press, 1964), pp. 13-21. See also a later discussion of the same issue in P. G. Bradley, The Economics of Crude Oil Production (Amsterdam: North-Holland Publishing Co., 1967), pp. 8-12.

⁵Lovejoy and Homan, p. 16; emphasis in the original.

⁶J. Hodges quoted in *ibid.*, p. 16.

⁷Bradley, pp. 8-9.

⁸Lovejoy and Homan, p. 17.

⁹*Ibid.*

¹⁰*Ibid.* It should be pointed out that the search for a better method of accounting of economic cost of crude oil production continued. Bradley, for example, subsequently developed the concept of supply price (mentioned above in the present volume) based on payments needed to secure all necessary factors of production, considered preferable by some analysts. See Bradley, p. 10 and ch. 2.

¹¹It should be stressed that costs will vary over time and that even producing oil from two wells will not cost the same amount. Lead times may be several years long (e.g., offshore oil) before it is known what the cost of production is.

¹²As a result, regulated firms might be expected to show less interest than unregulated firms in technological improvements which lower their costs or in preventing cost increases generally. If a regulated firm was always allowed to change its average cost, indeed no incentive would exist to hold the cost down. In practice, however, each price increase is subject to public hearings resulting in a time gap. Consequently, the incentive to hold costs down, while somewhat attenuated, is not totally absent for regulated monopolies.

¹³The questions of government incentives available to the oil producers, as well as that of revenue sharing between the industry and the two levels of government are treated separately in the following chapter. The proposed National Energy Program estimates the revenue shares from oil and natural gas production among the federal and provincial governments and industry between 1980 and 1983 as follows: federal 24 percent, provinces 43 percent, and industry 33 percent (National Energy Program, p. 108). This distribution has, however, been disputed by Alberta's Energy Minister as well as by some industry officials. The dispute centres on the method of calculating the shares. See, for instance, issues of *The Calgary Herald*, Nov. 13, 1980, where the Chairman of Shell Oil estimated the federal share at 45 percent and that of industry at 24 percent; or Nov. 29, 1980, where the Alberta Energy Minister estimated the provincial share at 28 percent and industry's share at 42 percent.

¹⁴It would not be inevitable, in fact not necessary, if Canada was already self-sufficient in oil and enjoyed the prospect of cheap domestic oil supplies into a very distant future.

¹⁵See the rigorous analysis of the case of insulating Canadian consumers from the world price of oil in J. F. Helliwell, "Can Canada be Insulated from Developments Abroad?" prepared for the Ontario Economic Council Conference on Adjustment, June 3-4, 1980.

¹⁶It is possible to think of the recent financial difficulties of the Chrysler Corporation and other North American automakers as being at least partially caused by their slow reaction to changed economic circumstances on this continent and producing the 'wrong' types of cars. But it must be said that if the North American consumers had not been insulated from the world price of oil for so long, Chrysler and others would have received their market signals much earlier with consequences possibly less severe than those seen in the auto market today.

¹⁷It should be recognized that the collection of 'excess' profits (or rents) by a government can also be done through royalty payments. In Canada, for example, the petroleum producing provinces collect a vast portion of their oil and gas revenues through such payments.

¹⁸In the U.S., for example, a Windfall Profits Tax has recently been enacted retroactive to March 1, 1980. The new law requires a complex categorization of oil produced from that date and assigns the basic responsibility for doing so to the oil producers. The operators of producing wells must classify their oil into one of the three established tiers (Tier 1: all pre-1979 oil; Tier 2: stripper wells and Naval Petroleum Reserve oil; Tier 3: newly discovered oil, heavy oil and enhanced recovery) and it is then the purchaser who actually becomes responsible for withholding the tax from the amount he pays the oil producer. Once the category of oil is established, a base price is established which in turn determines the amount of windfall profit on which the tax is based. Generally, a producer will be subject to a tax rate of 70 percent, 60 percent and 30 percent on the windfall profit on Tier 1, 2 and 3 oil respectively. The new law is complex, allowing for exceptions, adjustments and qualifications, but this is its basic structure. What is important and should be kept in mind if and when a similar law is considered for Canada is that the Windfall Profits Tax law has a specified time horizon and that the anticipated amount of tax collected will be spent in a scheduled orderly fashion (including energy-related expenditures). For more detail, see "Windfall Profits Tax: Finally a Reality," Energy, Spring 1980, pp. 4-24.

¹⁹An indication of the latter is the recently created Petroleum Monitoring Agency. The PMA should also serve the purpose of placing information in the public domain.

Chapter 7

GOVERNMENT INCENTIVES IN CANADA'S PETROLEUM INDUSTRY

W. B. Friedenber, A. J. Nixon and Z. C. Slagorsky¹

Introduction

In Chapters 3 and 4 attention was paid to the role of prices and costs as factors influencing oil demand and supply. On the demand side there are many additional factors that can influence the amount of energy that is used. The overall rate of economic growth has been taken into account. The potential impact of energy conservation programs has also been examined, although the manner of implementing such programs has not. A number of specific measures have been included in the Fall 1980 federal budget.

On the supply side, the costs of alternative sources of oil have already been examined. They play a major role in determining how much oil is to be produced. In addition, government incentives in Canada's oil and gas industry are an integral part of the overall management of Canada's oil and gas resources. The incentives offered to the industry have changed over time reflecting new developments in domestic and world market conditions. The 1970s brought significantly higher prices for oil and gas and the rapid depletion of conventional reserves. Both developments have stimulated new government incentives in Canada's oil and gas industry.

Description of the Incentives

Until the recently announced National Energy Program, the main incentives offered to the industry operated through the federal income tax. The expensing provisions and the various depletion allowances have been particularly important in influencing the distribution of revenue from a barrel of oil. The exact impact these and other incentives have had on a company's current cash picture have depended on that company's level of production, its costs, and the division of these costs between various activities.

Table 7.1 presents a summary outline of the main government incentives that have been available to Canada's petroleum industry.²

TABLE 7.1
INCENTIVES IN THE CANADIAN OIL AND GAS INDUSTRY^a

Incentive	Objectives	Application	Credit to:
Resource Allowance	- to reduce the effective rate of federal tax (to compensate for non-deductibility of royalty in computing taxable income)	- 25% deduction from income on a defined basis	- deducted from taxable income
Earned Depletion	- to encourage the undertaking of risks inherent in resource exploration and development	1. lesser of 1/4 of resource profits or 33-1/3% earned depletion on conventional oil and gas operations v oil sands operations (including social assets and townsite facilities)	- deducted from taxable income
1. Ordinary depletion		2. 50% earned depletion on enhanced recovery and oil sands equipment, up to 50% of total income after deducting ordinary depletion	
2. Supplementary depletion		3. 66-2/3% earned depletion on exploratory drilling costs in excess of \$5 million per well, up to the remaining income after deducting all other depletion allowances	
3. Frontier depletion ^b		- 100% of defined Canadian exploration expenses	- deducted from taxable income
Exploration Expensing	- to allow recovery of most of the investment before taxes are paid on resource income	- 30% of defined Canadian development expenses, 100% for new mines which includes oil sands operations	- deducted from taxable income
Development Expensing			

FEDERAL

TABLE 7.1 (Cont'd)

PROVINCIAL		
ALBERTA		
Exploratory Drilling Incentive System	- stimulate exploratory drilling activity - accelerate discovery of petroleum reserves - stimulation of rural economies	- certified drilling program earns credit according to schedule outlined in regulations
Geophysical Incentive Program	- stimulate level of geophysical activity - retain nucleus of skilled geophysical personnel in Alberta	- certified geophysical program earns credit according to formula
Royalty Tax Credit	- increase industry cash flow by reducing royalties payable	- lesser of (1) 25% of corporations attributed Alberta royalty income, or (2) \$1,000,000
Alberta Royalty Rebate	- increase industry cash flow by reducing provincial tax payable (to compensate for royalty non-deductibility)	- rebate calculated using formula. If Alberta tax payable is less than this amount take tax payable as rebate
SASKATCHEWAN		
Approved Expenditure Grants	- increase investment in oil and gas industry	- credit calculated as 75% of approved expenditures
Certified Exploratory Well Grants	- increase exploratory drilling activity	- credits calculated with formula
Saskatchewan Royalty Rebate	- increase industry cash flow by reducing royalties payable	- difference between provincial tax payable and provincial tax due if royalties were deductible but not resource allowance
B.C. Royalty & Deemed Income Rebate	- increase industry cash flow by reducing royalties payable	- difference between provincial tax payable and provincial tax due if royalties were deductible but not resource allowance
BRITISH COLUMBIA		
Exploratory Drilling Incentive System	- stimulate exploratory drilling activity - accelerate discovery of petroleum reserves - stimulation of rural economies	- certified drilling program earns credit according to schedule outlined in regulations
Geophysical Incentive Program	- stimulate level of geophysical activity - retain nucleus of skilled geophysical personnel in Alberta	- certified geophysical program earns credit according to formula
Royalty Tax Credit	- increase industry cash flow by reducing royalties payable	- lesser of (1) 25% of corporations attributed Alberta royalty income, or (2) \$1,000,000
Alberta Royalty Rebate	- increase industry cash flow by reducing provincial tax payable (to compensate for royalty non-deductibility)	- rebate calculated using formula. If Alberta tax payable is less than this amount take tax payable as rebate
SASKATCHEWAN		
Approved Expenditure Grants	- increase investment in oil and gas industry	- credit calculated as 75% of approved expenditures
Certified Exploratory Well Grants	- increase exploratory drilling activity	- credits calculated with formula
Saskatchewan Royalty Rebate	- increase industry cash flow by reducing royalties payable	- difference between provincial tax payable and provincial tax due if royalties were deductible but not resource allowance
B.C. Royalty & Deemed Income Rebate	- increase industry cash flow by reducing royalties payable	- difference between provincial tax payable and provincial tax due if royalties were deductible but not resource allowance

SOURCES: (1) Canadian Taxation of Mining Income, Holland, Kemp, Ernst & Ernst, CCH Canadian Limited, 1978.
 (2) Canadian Income Taxation of Oil and Gas, Canadian Petroleum Tax Society, April 10, 1979.
 (3) Provincial Tax and Royalty Development Oil and Gas Resource Operations, Cochrane, Twenty-seventh Tax Conference, 1975.

^aIn this table we have listed the incentives provided by the federal government and the three western provincial governments since it is in Alberta, Saskatchewan and British Columbia that essentially all of the oil and gas activity is centred. The exploration activity off Newfoundland's coast earns 'frontier depletion'.

^bTerminated on March 31, 1980.

Both levels of government, federal and provincial, may be viewed as offering the Canadian oil industry an incentive package, each package containing one or more incentive schemes each individually tailored to the respective levels of government's jurisdictional domain and their economic, social and political objectives. With this in mind, Table 7.1 has been organized vertically, presenting first the federal incentives and then the incentive packages of Alberta, Saskatchewan and British Columbia. The federal incentive package has operated through the federal income tax. The incentive packages offered by the three producing provinces operate to reduce monies payable to the provincial governments.

There are basically two broad categories of incentives: earned and automatic. The resource allowance offered by the federal government is automatic in that there are no expenditure requirements imposed upon the industry. The depletion allowance and the exploration and development expensing programs are earned incentive schemes. Expenditures must be made before a producer would qualify to receive credit under these schemes.

There is a tendency to promote earned incentive schemes since these schemes can be more effectively directed towards specific activities within the industry. This tendency was illustrated when the federal government made depletion an earned allowance instead of an automatic deduction as it had been prior to 1971. All of the provincial incentive schemes shown in Table 7.1, with the notable exceptions of the Alberta Royalty Tax Credit and the provincial royalty rebate schemes, must be earned by the industry through qualified expenditures.

Not shown in Table 7.1 are the royalty schemes of the provinces, but it should be noted that they have also been designed to provide an incentive to the industry. Alberta, Saskatchewan and British Columbia royalty schemes distinguish between 'old' and 'new' oil, the demarcation date being January 1, 1974. The royalty rates for new oil are lower than those for old, which represents a formal recognition by government of the rising costs in this industry, and thus provides an incentive to producers in their search for new reserves. A 1979 decision by the Alberta legislature reduced the royalty rate for low (less than 1,200 barrels a month) producing wells. Effectively, this decision reduces the costs to the operator and thus encourages the extraction of oil from marginal wells rather than shutting them down. The Saskatchewan royalty scheme incorporates an 'area adjustment modifier' which is another variable designed in recognition of the

costs faced by the petroleum industry. This variable is designed to reduce the royalty rate on production from high cost areas; reflecting more difficult terrain and stratigraphies.

The incentives offered to oil sands production in Alberta included the world price for oil,³ a supplementary depletion allowance on top of ordinary depletion, 100 percent development expensing which includes social infrastructure investment and the right to deduct royalties in calculating income tax. Other incentives offered are negotiated separately between the government and operator of each plant.

Financial Effects of the Incentives

The incentives in Canada's oil and gas industry have the effect of improving the cash position of firms in the industry and thereby the rate of return that can be realized on investment in either exploration or development. To illustrate, an expenditure of \$2.50 on exploration and \$1.50 on development (all in Alberta) would decrease corporate tax by about \$2.00. This tax relief would come mainly from the federal government which would give up \$1.54 per barrel in tax revenue. The provincial government would give up \$0.48 per barrel in tax revenue.

More generally, the distribution of revenue from a barrel of oil between the two levels of government and industry depends on the price of the oil and on the source of the oil (conventional recovery, enhanced oil recovery, oil sands, etc.), the expenditures on exploration and on development, and whether revenue from land sale and rental payments are included or excluded. Under the set of assumptions used in our analysis, the distribution of revenue from a barrel of conventional oil produced in Alberta was the federal government (14 percent), the provincial government (44 percent), industry, including operating costs, (42 percent).⁴

The National Energy Program Proposals

The National Energy Program, announced by the federal government on October 28, 1980, is changing much of the incentives program to grants funded by annual appropriations rather than tax allowances. The proposed oil and gas incentives under the National Energy Program are summarized in Table 7.2. The program would also include a wide variety of other measures, many of which have implications of oil supply and demand, including:

- wellhead prices that differ according to whether oil is derived from conventional, tertiary recovery or oil sands sources;
- a blended price system to refiners, including a new Petroleum Compensation Charge to shift the higher cost of imported oil from the taxpayer to the oil consumer;
- a new natural gas and gas liquids tax applied to both domestic and export sales;
- a new tax on net oil and gas production revenue, initially set at 8 percent;
- new legislation covering oil and gas exploration and development on lands that fall within federal jurisdiction; and
- a number of specific measures to achieve more effective use of existing oil supplies and to encourage substitution away from oil.

TABLE 7.2

OIL AND GAS INCENTIVES UNDER THE NATIONAL ENERGY PROGRAM
(percentages of allowable expenditures)

Year	Canadian Ownership Rates ^b	Provincial Lands			Canada Lands				
		Depletion ^a	Incentive Payments		Depletion ^a	Incentive Payments			
			0-50%	50-75%		75%+	0-50%	50-75%	75%+
Exploration									
1981		33-1/3	nil	nil	35	33-1/3	25	35	80
1982		20	nil	10	35	33-1/3	25	45	80
1983		10	nil	10	35	33-1/3	25	45	80
1984		nil	nil	15	35	33-1/3	25	50	80
Development									
1981		nil	nil	nil	20	nil	nil	nil	20
1982		nil	nil	10	20	nil	nil	10	20
1983		nil	nil	10	20	nil	nil	10	20
1984		nil	nil	10	20	nil	nil	10	20
Non-conventional and tertiary projects, and crude oil upgraders									
1981		33-1/3	nil	nil	20	(not applicable)			
1982		33-1/3	nil	10	20	(not applicable)			
1983		33-1/3	nil	10	20	(not applicable)			
1984		33-1/3	nil	10	20	(not applicable)			

^aDepletion will be earned on qualifying expenditures net of any incentive payments.^bCanadian-owned firms must also be Canadian controlled to be eligible for the larger incentive payments. Individual Canadians are eligible for the same payments as firms with a Canadian Ownership Rate of at least 75 percent.

NOTES TO TABLE 7.2

Measurement of Canadian ownership rates and determination of Canadian control is the responsibility of the Petroleum Monitoring Agency, established August 1, 1980. (A proposal released November 21, 1980 contains draft regulations.)

The Petroleum Incentives Program is the responsibility of the proposed Petroleum Incentives Board. ("The Basic Rules--A Framework" was released by the Department of Energy, Mines and Resources on December 19, 1980. Table 7.2 is drawn from that document. More detailed "Guidelines" are to be published early in 1981.)

Also, there has been the introduction in Parliament on December 9, 1980 of Bill C-48, an act to regulate the oil and gas interests in Canada lands and to amend the Oil and Gas Production and Conservation Act, which would give the Crown a 25 percent carried interest in all federal lands where production had not taken place, other than for test purposes, before January 1, 1976. It would also require a minimum of 50 percent Canadian ownership before actual new production of oil or gas can begin under the new regime, with such production licences to be valid for ten years from the start of production.

Footnotes

¹Summary and updating by John A. Dawson of W. B. Friedenber; A. J. Nixon; and Z. C. Slagorsky, "Government Incentives in Canada's Petroleum Industry" (Calgary: Canadian Energy Research Institute, March 1980), Working Paper 80-1.

²Frontier depletion expired at March 31, 1980.

³In the spring of 1980 the federal government withdrew the commitment that oil sands oil would receive world prices.

⁴See Friedenber, Nixon and Slagorsky, Table 2, p.19, where the revenue distribution calculations are shown, and Table 3, p.28, where the effects of changes in price and other factors are indicated. A recent study by Paul Ziff, and Rory Hankel, The Current Canadian Energy Pricing Dispute/Negotiations - A Critical Analysis of the Issues, (Calgary: Greenshields Research Report, September 1980), examines the revenue-sharing implications of a number of recent proposals for policy change.

APPENDICES

Appendix A

ESTIMATES OF PRICE ELASTICITIES
BY FUEL TYPE AND END USE SECTOR

The measuring device which reveals consumer sensitivity to changes in the price of a particular commodity is called the 'own-price' elasticity. The lower the absolute value of the own-price elasticity measure, the less responsive is demand to changes in price.

Table A.1 reports estimates, and in some cases a range of estimates, for own-price elasticities for individual fuel types and total energy in each end-use consuming sector. Sectors in which there are large substitution possibilities or inefficient uses of energy are expected to be the most responsive to energy price changes. As Table A.1 indicates, the industrial sector generally verifies this response. The transportation sector, on the other hand, has a limited range of substitution possibilities since it is heavily oriented towards the consumption of fossil fuels, specifically motor gasoline and diesel oil. This sector is expected to be much less responsive to price changes in the short run. Transportation energy savings are largely dependent upon technological advances and are, therefore, long-run savings.

Three additional points concerning Table A.1 are required. The first is the wide range of elasticities reported for coal usage in the industrial sector. A 1964 cross section study estimated the own-price elasticity to be -4.2 which revealed that coal consumption was very responsive to changes in price.¹ The lower estimate of -1.5 was the result of a time series analysis which evidenced that over time consumers of coal in the industrial had become less responsive to changes in price, perhaps as the inefficiencies in consumption were eliminated. The second point is that the estimated own-price elasticity for natural gas combined the two end-use sectors: residential and commercial. Third, the estimates of the own-price elasticities for total energy are generally less than those for specific fuel types because there are more substitution possibilities among fuel types than for total energy.

¹James A. Coombs, "A Cross-Sectional Study of Energy Demand in Canadian Manufacturing Industries, 1964" (Master of Arts Thesis, Department of Economics, Queen's University, September 1969).

TABLE A.1
ESTIMATED OWN-PRICE ELASTICITIES BY FUEL TYPE AND END-USE SECTOR

	Motor Gasoline	Fuel Oil	Diesel	Electricity	Coal	Natural Gas	LPG	Total Fossil Fuels	Total Energy
Residential				-0.14				-0.7	-0.32
Commercial				-0.31		-0.6 to -0.15			-0.31
Industrial	-1.6	-1.3			-1.5 to -4.2	-1.3 to -2.2	-2.4		-0.30 to -0.59
Transportation	-0.18 to -0.45		-1.26						

SOURCES: Canada, Department of Energy Mines and Resources, Energy Demand Projection, A Total Energy Approach (Ottawa: Supply and Services, 1977), Report ER 77-4.
E. R. Berndt, "Canadian Energy Demand and Economic Growth," in Oil in the Seventies (Vancouver: The Fraser Institute, 1977).

APPENDIX TABLE B.1

POSSIBLE SAVINGS IN OIL CONSUMPTION
THROUGH HIGHER OIL PRICE INCREASES
1985, 1990 AND 2000
($10^3 \text{ m}^3/\text{d}$)

<u>1985 Oil Consumption</u>		
a) '70s Trend' Forecast	349	
b) 'Higher Oil Price' Forecast	320	
1985 Oil Savings		29
1980-1985 Accumulated Savings		36 10^6 m^3
<u>1990 Oil Consumption</u>		
a) '70s Trend' Forecast	395	
b) 'Higher Oil Price' Forecast	336	
1990 Oil Savings		59
1986-1990 Accumulated Savings		85 10^6 m^3
<u>2000 Oil Consumption</u>		
a) '70s Trend' Forecast	506	
b) 'Higher Oil Price' Forecast	371	
2000 Oil Savings		135
1991-2000 Accumulated Savings		358 10^6 m^3
1980-2000 Accumulated Savings		479 10^6 m^3

NOTE: The 1979 base is taken to be 301 thousand cubic metres per day. The '70s Trend' forecast assumes a 2.5 percent average annual growth rate (AAGR) in oil consumption throughout the whole period 1979-2000.

For the assumptions to the 'Higher Oil Price' forecast see the note to Table 3.3.

APPENDIX TABLE C.1
ESTIMATED OIL PRODUCTION FROM VARIOUS SOURCES
(thousands of cubic metres per day)

	(i)	(ii)	(iii)	(iv)	(v)	
	Conventional Oil	Frontier Oil	Oil Sands	Production	Heavy Oil Upgrading	Enhanced Recovery
						Light & Med. Oil Heavy Oil
1980	209 (195-213)	-	26 (24-30)	36 (14-36)	-	2 (8-24) .5 (0-1)
1985	131 (112-145)	14 (0-41)	38 (32-41)	26 (13-36)	6 (?)	12 (3-28) 4 (1-14)
1990	119 (90-174)	72 (0-175)	86 (79-99)	28 (12-43)	12 (8-16)	33 (5-67) 9 (2-17)
1995	94 (63-150)	500 (0-?)	126 (112-155)	30 (13-48)	16 (8-24)	23 (3-55) 11 (3-20)
2000	24 (?)	(?)	143 (129-150)	27 (14-46)	(?)	4 (?) 21 (0-42)

APPENDIX TABLE C.2
ESTIMATED SUPPLY PRICES OF OIL FROM VARIOUS SOURCES
(1980 \$/m³)

Type of Oil	Supply Price	
	Base Case	Low and High
i) Conventional oil	71.80	48.96 - 94.65
ii) Enhanced recovery		
Light & medium oil	31.46 - 106.79	31.46 - 106.79
Heavy oil	47.95	35.05 - 73.38
Upgraded heavy oil	83.19	70.29 - 108.62
iii) Heavy oil		
Production	56.32	41.22 - 79.61
Upgrading	35.24	14.91 - 56.83
Upgraded heavy oil	91.56	76.46 - 114.85
iv) Oil sands	107.48	78.66 - 127.68
v) Frontier oil	97.54	78.03 - 117.05



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